AMERICAN ELECTRIC POWER CO INC
Form 10-Q
November 06, 2006

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

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **September 30, 2006**
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
Yes X No __

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer X Accelerated filer __Non-accelerated filer __

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

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).
Yes __ No X

AEP Generating Company, AEP Texas North Company, Columbus Southern Power Company, Kentucky Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants at October 31, 2006
AEP Generating Company	1,000
	($1,000 par value)
AEP Texas Central Company	2,211,678
	($25 par value)
AEP Texas North Company	5,488,560
	($25 par value)
American Electric Power Company, Inc.	395,572,735
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Columbus Southern Power Company	16,410,426
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Kentucky Power Company	1,009,000
	($50 par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
September 30, 2006

SIGNATURE

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
ADFIT	Accumulated Deferred Federal Income Taxes.
ADITC	Accumulated Deferred Investment Tax Credits.
AEGCo	AEP Generating Company, an AEP electric generating subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated entities.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing their generating capacity allocation. AEPSC acts as the agent.
CTC	Competition Transition Charge.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
ECAR	East Central Area Reliability Council.
EDFIT	Excess Deferred Federal Income Taxes.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EPACT	Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.

GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipe Line Company LP, a former AEP subsidiary that was sold in January 2005.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPP	Independent Power Producers.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System’s Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTB	Price-to-Beat.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PURPA	Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned or leased by AEGCo and I&M.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor’s.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the FASB.
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.

Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, 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.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including implementation of EPACT and membership in and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

EXECUTIVE OVERVIEW

Several factors, both positive and negative, contributed to our performance in the third quarter of 2006. We continued receiving favorable outcomes in various regulatory activities resulting in increased revenues. We also 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 related to our Plaquemine Cogeneration Facility in connection with the pending sale to Dow Chemical Company.

Regulatory Activity

Our significant regulatory activity progressed with the following major developments:

- In July 2006, an ALJ rendered an initial decision to the FERC recommending that current transmission rates in PJM are unjust and unreasonable and should be redesigned to replace the PJM license plate rates effective April 1, 2006. If approved by the FERC, the new regional rates would result in parties outside of the AEP zone in PJM contributing a significant portion of AEP's transmission revenue requirement, some of which may be treated as a refund to retail customers. The favorable impact of the initial ALJ decision is not determinable pending the decision of the FERC and subject to analysis of refunds to retail customers, if any.
- In July 2006, the FERC approved our request for use of an incentive rate treatment for our proposed 550-mile 765 kV transmission line project. The approval is conditioned upon PJM including the project in its formal Regional Transmission Expansion Plan, which should be finalized in early 2007.
- In July 2006, the West Virginia Public Service Commission approved a settlement agreement in APCo and WPCo's base rate case, providing for a $44 million annual increase in rates effective July 28, 2006. These rates include a surcharge for recovery of the cost of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.
- In August 2006, an ALJ rendered an initial decision to the FERC indicating the rate design for recovery of SECA charges was flawed and that the SECA rates charged were unfair, unjust and discriminatory and that refunds should be made. We believe this decision is contrary to other FERC rulings and intend to defend against a SECA rates refund.
- In September 2006, the Virginia SCC's chief hearing examiner issued an opinion recommending disallowance of our $21 million environmental and reliability cost recovery case filed in June 2005. We subsequently wrote off our related assets which reduced pretax earnings by $36 million in the third quarter of 2006. We believe the hearing examiner's recommendation is contrary to the law and have urged the Virginia SCC not to adopt that recommendation.
- In September 2006, we announced our intention to file transmission and distribution wires rate cases in Texas in late 2006. We anticipate requesting an $83 million increase for TCC and a $25 million increase for TNC.
- In September 2006, we filed a notice of intent in Oklahoma to file a base rate case in November 2006.
- In October 2006, we filed state environmental permit applications for clean-coal power plants in Ohio and West Virginia, representing another step towards the commencement

of construction of our IGCC plants.

- In October 2006, we implemented an interim increase in Virginia retail base rates, subject to refund, as ordered by the Virginia SCC related to our $198 million net base rate case filing from May 2006. Hearings are scheduled for December 2006.
- In October 2006, TCC issued $1.74 billion senior secured transition bonds as previously approved by the PUCT. In October 2006, TCC repaid $345 million of intercompany notes to AEP and also paid a special dividend of $585 million to AEP. We will use the remaining proceeds to reduce a portion of TCC's debt and equity.
- In October 2006, the IURC denied our request to revise I&M's book depreciation rates without adjusting base tariff rates.

Fuel Costs

During 2006, spot market prices for coal and natural gas have declined. In contrast, market prices for fuel oil have increased and continue to be volatile. We still expect an approximate ten percent increase in coal costs during 2006 and a six to eight percent increase in 2007 even considering softening fuel markets and favorable transportation effects during the first nine months of the year. 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 $17 million for the first nine months of 2006 and expect additional under-recoveries for the remainder of 2006. Our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans, which are intended to recover increases in generation costs, including increased fuel costs. 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.

Barging Operations

With the exception of the Plaquemine Cogeneration Facility impairment in the third quarter of 2006, we achieved favorable 2006 results in our Investments - Other segment primarily due to our barging operations. AEP MEMCO LLC (MEMCO) handles the dispatching and logistics for our river operations, which consist primarily of coal deliveries to our plants, coal movement between plants for ensuring continued operations during market disruptions and transportation of bargeable commodities for third parties. MEMCO continues to benefit from strong market demand for barging services as well as a tight supply of barges, which allowed it to negotiate favorable annual freight contracts for 2006 and beyond for hauling a variety of commodities for third parties. The strong freight market, enhanced operating conditions when compared with the flooding and ice encountered during the first quarter of 2005, and the continued implementation of programs to maximize equipment use, all contributed to an increase in tonnage transported and a corresponding increase in earnings.

Power Generation Facility

In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for $64 million. We expect the sale to close in the fourth quarter of 2006. 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. In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years and we retain the right to any judgment paid by TEM for breaching the original PPA, as discussed in Note 5.

Assuming the sale closes, our future earnings will be favorably impacted by eliminating ongoing operating losses. These improvements will be partially offset by interest expense associated with continuing debt service obligations.

Dividend Increase

In October 2006, our Board of Directors approved a five percent increase in our quarterly dividend to $0.39 per share from $0.37 per share.

RESULTS OF OPERATIONS

Segments

Our principal operating business segments and their major activities are:

Utility Operations

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

Investments - Other

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

Our consolidated Income Before Discontinued Operations for the three and nine months ended September 30, 2006 and 2005 were as follows (Earnings and Weighted Average Number of Basic Shares Outstanding in millions):

	Three Months Ended September 30,				**Nine Months Ended September 30,**			
	2006		**2005**		**2006**		**2005**	
	Earnings	**EPS (c)**	**Earnings**	**EPS (c)**	**Earnings**	**EPS (c)**	**Earnings**	**EPS (c)**
Utility Operations	$ 379	$ 0.96	$ 352	$ 0.91	$ 904	$ 2.29	$ 952	$ 2.45
	)	)			)	)		
Investments - Other	(109(d)	(0.28(d)	28	0.07	(80(d)	(0.20(d)	32	0.08
All Other (a)	(2)	-	(5)	(0.01)	(7)	(0.02)	(45)	(0.12)
Investments - Gas Operations (b)	(3)	(0.01)	(10)	(0.03)	(2)	-	(2)	-
Income Before Discontinued Operations	$ 265	$ 0.67	$ 365	$ 0.94	$ 815	$ 2.07	$ 937	$ 2.41
Weighted Average Number of Basic Shares Outstanding		394		389		394		389

(a) All Other includes the parent company's guarantee revenues, interest income and expense, as well as other nonallocated costs.
(b) We sold our remaining gas pipeline and storage assets in 2005.
(c) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in AEP's assets and liabilities as a whole.
(d) Loss primarily due to an after-tax impairment of $136 million (approximately $0.34 per share) related to our Plaquemine Cogeneration Facility.

Third Quarter of 2006 Compared to Third Quarter of 2005

Income Before Discontinued Operations in the third quarter of 2006 decreased $100 million compared to the third quarter of 2005 principally due to an impairment of the Plaquemine Cogeneration Facility as a result of the pending sale and decreases in Utility Operations earnings related to lower transmission revenues from the loss of SECA rates and the write off of Virginia environmental and reliability regulatory assets pursuant to a hearing examiner's recommendation, which we have urged the Virginia SCC not to adopt. These decreases were partially offset by an earnings increase in Utility Operations primarily related to new retail rates implemented in Ohio and Kentucky and increased off-system sales margins.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Income Before Discontinued Operations for the nine months ended September 30, 2006 decreased $122 million compared to the nine months ended September 30, 2005 due to a $48 million decrease in Utility Operations earnings from decreases in transmission revenues from the loss of SECA rates and increases in operating expenses, partially offset by new retail rates implemented in Ohio and Kentucky. In addition, our Investments - Other segment earnings decreased $112 million from an impairment of the Plaquemine Cogeneration Facility related to the pending sale. These decreases were partially offset by a decrease of $38 million in interest expense, net of interest income, at the parent company.

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 margins represent utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
		(in millions)		
Revenues	$ 3,441	$ 3,237	$ 9,209	$ 8,623
Fuel and Purchased Energy	1,384	1,252	3,637	3,163
Gross Margin	2,057	1,985	5,572	5,460
Depreciation and Amortization	369	328	1,041	963
Other Operating Expenses	973	1,014	2,806	2,757
Operating Income	715	643	1,725	1,740
Other Income, Net	20	43	105	122
Interest Expense and Preferred Stock Dividend Requirements	161	145	475	445
Income Tax Expense	195	189	451	465
Income Before Discontinued Operations	$ 379	$ 352	$ 904	$ 952

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three and Nine Months Ended September 30, 2006 and 2005

	Three Months Ended	Nine Months Ended

	September 30, 2006	September 30, 2005	September 30, 2006	September 30, 2005
	(in millions of KWH)			
Energy Summary				
Retail:				
Residential	13,482	14,152	36,010	37,332
Commercial	10,799	10,900	29,149	29,204
Industrial	13,468	13,380	40,405	39,633
Miscellaneous	677	682	1,890	1,968
Subtotal	38,426	39,114	107,454	108,137
Texas Retail and Other	105	115	312	504
Total Retail	38,531	39,229	107,766	108,641
Wholesale	13,465	13,135	35,131	37,515
Texas Wires Delivery	7,877	8,093	20,338	20,348
Total KWHs	59,873	60,457	163,235	166,504

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 quarter and year-to-date periods ended September 30, 2006 and 2005 were as follows:

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(in degree days)			
Weather Summary				
Eastern Region				
Actual - Heating (a)	10	1	1,573	1,940
Normal - Heating (b)	7	7	1,999	1,995
Actual - Cooling (c)	685	834	914	1,122
Normal - Cooling (b)	688	674	970	955
Western Region (d)				
Actual - Heating (a)	0	0	664	795
Normal - Heating (b)	2	2	1,007	1,007
Actual - Cooling (c)	1,468	1,523	2,325	2,225
Normal - Cooling (b)	1,410	1,397	2,079	2,059

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

Third Quarter of 2006 Compared to Third Quarter of 2005

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

Third Quarter of 2005		$ 352
Changes in Gross Margin:		
Retail Margins	29	
Off-system Sales	75	
Transmission Revenues	(38)	
Other	6	
Total Change in Gross Margin		72
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(15)	
Asset Impairments and Other Related Charges	39	
Depreciation and Amortization	(41)	
Taxes Other Than Income Taxes	17	
Other Income, Net	(23)	
Interest and Other Charges	(16)	
Total Change in Operating Expenses and Other		(39)
Income Tax Expense		(6)
Third Quarter of 2006		$ 379

Income from Utility Operations Before Discontinued Operations increased $27 million to $379 million in 2006. The key driver of the increase was a $72 million net increase in Gross Margin, partially offset by a $39 million increase in Operating Expenses and Other.

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

- Retail Margins increased $29 million primarily due to the following:
  - A $72 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our Rate Stabilization Plans (RSPs) and a $12 million increase related to new rates implemented in Kentucky as approved in our base rate case;
  - A $20 million increase related to increased sales to municipal, cooperative and other wholesale customers primarily as a result of new power supply contracts; and
  - An $18 million increase related to the purchase of the Ohio service territory of Monongahela Power in December 2005; partially offset by
  - A $22 million decrease in financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market;
  - A $33 million decrease related to increased refunds to retail customers of a portion of off-system sales margins due to higher off-system sales and the reinstatement of the off-system sales margins sharing mechanism in West Virginia effective July 1, 2006 in conjunction with the West Virginia rate

case settlement;
- A $14 million increase in delivered fuel costs, which relates to AEP East companies with inactive, capped or frozen fuel clauses; and
- A $30 million decrease in usage related to mild weather. As compared to the prior year, we experienced an 18% decrease in cooling degree days in the eastern region and a 4% decrease in the western region.

- Margins from Off-system Sales for 2006 increased $75 million primarily due to positive margins from hedges of plant output and strong physical sales in the east, where AEP's generation availability factor was high in July and August when wholesale prices were favorable.
- Transmission Revenues decreased $38 million primarily due to the elimination of SECA revenues as of April 1, 2006. 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 3.

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

- Maintenance and Other Operation expenses increased $15 million primarily due to increases in generation expenses for base operations, maintenance and an abandonment of digital turbine control equipment at the Cook Plant, increases in transmission and distribution expenses related to vegetation management and storm restoration and the establishment of a regulatory asset for PJM administrative fees in 2005 which reduced expenses in the prior period, offset by the establishment of a net regulatory asset for recovery of prior years' Ohio ice storm damage costs and lower incentive pay accruals.
- Asset Impairments and Other Related Charges were $39 million in 2005 due to our commitment to a plan in September 2005 to retire two units at our Conesville Plant. We retired the two units effective December 29, 2005.
- Depreciation and Amortization expense increased $41 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases, higher depreciable property balances and the write off of Virginia environmental and reliability regulatory assets.
- Taxes Other Than Income Taxes decreased $17 million primarily due to adjustments related to real and personal property taxes and sales and use taxes.
- Other Income, Net decreased $23 million primarily related to the write off of carrying costs on Virginia environmental and reliability regulatory assets.
- Interest and Other Charges increased $16 million primarily due to additional debt issued in late 2005 and early 2006 and an increase in regulatory interest related to Texas regulatory liabilities partially offset by an increase in allowance for borrowed funds used during construction.
- Income Tax Expense increased $6 million due to the increase in pretax income.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Reconciliation of Nine Months Ended September 30, 2005 to Nine Months Ended September 30, 2006
Income from Utility Operations Before Discontinued Operations
(in millions)

Nine Months Ended September 30, 2005		$ 952
Changes in Gross Margin:		
Retail Margins	198	
Off-system Sales	2	
Transmission Revenues	(93)	

Other		5	
Total Change in Gross Margin			112
Changes in Operating Expenses and Other:			
Maintenance and Other Operation		(42)	
Gain on Disposition of Assets, Net		(47)	
Asset Impairments and Other Related Charges		39	
Depreciation and Amortization		(78)	
Other Income, Net		(16)	
Interest and Other Charges		(30)	
Total Change in Operating Expenses and Other			(174)
Income Tax Expense			14
Nine Months Ended September 30, 2006		$	904

Income from Utility Operations Before Discontinued Operations decreased $48 million to $904 million in 2006. The key driver of the decrease was a $174 million increase in Operating Expenses and Other, offset by a $112 million increase in Gross Margin and a $14 million decrease in Income Tax Expense.

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

- Retail Margins increased $198 million primarily due to the following:
  - A $175 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a $22 million increase related to new rates implemented in Kentucky as approved in our base rate case and a $12 million increase related to new rates implemented in Oklahoma in June 2005;
  - A $21 million increase in financial transmission rights revenue, net of congestion, due to improved management of price risk related to serving retail load within PJM under current transmission constraints;
  - A $58 million increase related to increased usage and customer growth in the industrial and commercial classes of which $47 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005; and
  - A $50 million increase related to increased sales to municipal, cooperative and other wholesale customers primarily as a result of new power supply contracts; partially offset by
  - An $84 million increase in delivered fuel cost, which relates to the AEP East companies with inactive, capped or frozen fuel clauses;
  - A $66 million decrease in usage related to mild weather. As compared to the prior year, our eastern region and western region experienced 19% and 17% declines, respectively, in heating degree days. Also compared to the prior year, our eastern region experienced a 19% decrease in cooling degree days. These decreases were partially offset by an increase of 5% in cooling degree days in the western region; and
  - A $15 million decrease related to increased refunds to retail customers of a portion of off-system sales margins due to higher off-system sales and the reinstatement of the off-system sales margins sharing mechanism in West Virginia effective July 1, 2006 in conjunction with the West Virginia rate

case settlement.

- Transmission Revenues decreased $93 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $19 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 3.

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

- Maintenance and Other Operation expenses increased $42 million primarily due to increases in generation expenses related to base operations, maintenance and planned and forced plant outages, distribution expenses related to vegetation management and the establishment of a regulatory asset for PJM administrative fees in 2005 which reduced expenses in the prior period. These increases were partially offset by favorable variances related to expenses from the January 2005 ice storm in Ohio and Indiana, decreases related to the sale of STP in May 2005 and lower incentive accruals.
- Asset Impairments and Other Related Charges were $39 million in 2005 due to our commitment to a plan in September 2005 to retire two units at our Conesville Plant. We retired the two units effective December 29, 2005.
- Gain on Disposition of Assets, Net decreased $47 million resulting from revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase-and-sale agreement from the sale of our REPs in 2002. In 2005, we 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 $78 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases, higher depreciable property balances and the write off of Virginia environmental and reliability regulatory assets.
- Other Income, Net decreased $16 million primarily due to the write off of carrying costs on Virginia environmental and reliability regulatory assets and a decrease in Ohio carrying costs income as a result of the implementation of the Ohio rate stabilization plans in January 2006, partially offset by an increase in the allowance for equity funds used during construction.
- Interest and Other Charges increased $30 million from the prior period primarily due to additional debt issued in late 2005 and early 2006 and increasing interest rates, partially offset by an increase in allowance for borrowed funds used during construction.
- Income Tax Expense decreased $14 million due to the decrease in pretax income.

Investments - Other

Third Quarter of 2006 Compared to Third Quarter of 2005

Loss Before Discontinued Operations from our Investments - Other segment was $109 million in 2006 compared to income of $28 million in 2005. The change was primarily due to a $136 million after-tax impairment of the Plaquemine Cogeneration Facility related to the pending sale and a $32 million after-tax gain on the sale of Pacific Hydro Limited in the third quarter of 2005, partially offset by favorable barging activity at MEMCO due to strong demand and a tight supply of barges resulting in increased barge freight rates. Also, the third quarter 2006 operating conditions for our barging operations improved from 2005 when Hurricane Katrina increased operating costs.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Loss Before Discontinued Operations from our Investments - Other segment was $80 million in 2006 compared to income of $32 million in 2005. The change was primarily due to a $136 million after-tax impairment of the

Plaquemine Cogeneration Facility related to the pending sale and a $32 million after-tax gain on the sale of Pacific Hydro Limited in the third quarter of 2005, partially offset by favorable barging activity at MEMCO due to strong demand and a tight supply of barges resulting in increased barge freight rates. Additionally, 2006 operating conditions for our barging operations improved from 2005 when hurricanes, severe ice and flooding caused increased operating costs.

Other

Parent

Third Quarter of 2006 Compared to Third Quarter of 2005

The parent company's Loss Before Discontinued Operations decreased $3 million from 2005 primarily due to lower interest expense as a result of the maturity of senior unsecured notes of $396 million in the second quarter of 2006, partially offset by higher interest expense due to the issuance of $345 million of senior notes in June 2005.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

The parent company's Loss Before Discontinued Operations decreased $38 million from 2005 primarily due to lower interest expense and associated buyback costs related to the redemption of $550 million of senior unsecured notes in April 2005 and increased affiliated interest income related to favorable results from the corporate borrowing program.

Investments - Gas Operations

Third Quarter of 2006 Compared to Third Quarter of 2005

The Loss Before Discontinued Operations from our Gas Operations segment improved $7 million primarily related to results from gas contracts that were not sold with the gas pipeline and storage assets.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

The Loss Before Discontinued Operations from our Gas Operations segment was essentially flat. Prior year results included one month of HPL's operations due to the sale of HPL in January 2005. Current year results relate primarily to gas contracts that were not sold with the gas pipeline and storage assets.

AEP System Income Taxes

The decrease in income tax expense of $63 million between the third quarter of 2006 and the third quarter of 2005 is primarily due to a decrease in pretax book income.

The decrease in income tax expense of $77 million between the nine months ended September 30, 2006 and the nine months ended September 30, 2005 is primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization ($ in millions)

	September 30, 2006		December 31, 2005	
	$ 12,763	57.0%	$ 12,226	57.2%

Long-term Debt, including amounts due within one year					
Short-term Debt		23	0.1	10	0.0
Total Debt		12,786	57.1	12,236	57.2
Common Equity		9,525	42.6	9,088	42.5
Preferred Stock		61	0.3	61	0.3
Total Debt and Equity Capitalization	$	22,372	100.0%	$ 21,385	100.0%

The amount of our common equity increased primarily due to earnings exceeding the amount of dividends paid in 2006. As a result, our ratio of total debt to total capital improved from 57.2% to 57.1%.

In September 2006, the FASB issued SFAS 158 related to phase one of its pension and postretirement benefit accounting project. It could have a negative impact on our debt to capital ratio when reported at December 31, 2006. The new standard requires the recognition of an additional minimum liability for fully-funded pension and postretirement benefit plans, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 deferral and amortization of net actuarial gains and losses. This could require recognition of a significant net-of-tax accumulated other comprehensive income reduction to common equity for those jurisdictions where a regulatory asset cannot be recorded. We estimate regulatory assets could offset as much as two-thirds of any net-of-tax accumulated other comprehensive income reduction. The effective date is fiscal years ending after December 15, 2006.

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 September 30, 2006, our available liquidity was approximately $3.2 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		259	
Total Liquidity Sources		3,259	
Less: Letter of Credit Drawn		34	
Net Available Liquidity	$	3,225	

In April 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion on terms more economically favorable than the previous agreements. The amended facilities are structured as two $1.5 billion credit facilities, each with an option to issue up to $200 million as letters of credit.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain covenants that 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 September 30, 2006, this contractually-defined percentage was 54.2%. Nonperformance of these covenants could result in an event of default under these credit agreements. At September 30, 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 amended revolving credit facilities do not contain a material adverse change clause.

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 the utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At September 30, 2006, all utility subsidiaries were comfortably in compliance with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At September 30, 2006, our utility subsidiaries had not exceeded those authorized limits.

Credit Ratings

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

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

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

Cash Flow

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

	Nine Months Ended September 30,	
	2006	**2005**
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 401	$ 320
Net Cash Flows From Operating Activities	2,213	1,699
Net Cash Flows Used For Investing Activities	(2,474)	(60)
Net Cash Flows From (Used For) Financing Activities	119	(1,110)
Net Increase (Decrease) in Cash and Cash Equivalents	(142)	529
Cash and Cash Equivalents at End of Period	$ 259	$ 849

Cash from operations, bank-sponsored receivables purchase agreement and short-term borrowings provide 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 September 30, 2006, we had credit facilities totaling $3 billion to support our commercial paper program without an outstanding balance. The maximum amount of commercial paper outstanding during the nine months ended September 30, 2006 was $325 million. The weighted-average interest rate for our commercial paper during the first nine months of 2006 was 4.96%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

	Nine Months Ended September 30, 2006	2005
	(in millions)	
Net Income	$ 821	$ 963
Less: Discontinued Operations, Net of Tax	(6)	(26)
Income Before Discontinued Operations	815	937
Noncash Items Included in Earnings	1,164	987
Changes in Assets and Liabilities	234	(225)
Net Cash Flows From Operating Activities	$ 2,213	$ 1,699

The key drivers of the increase in cash from operations for the first nine months of 2006 were no Pension Contributions to Qualified Plan Trusts in 2006 compared with a $306 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 our increased fuel costs.

Net Cash Flows From Operating Activities were $2.2 billion in 2006 consisting primarily of Income Before Discontinued Operations of $815 million adjusted for noncash charges of $1.2 billion, which principally includes $1.1 billion for Depreciation and Amortization. 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 $235 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 $1.7 billion in 2005 consisting primarily of Income Before Discontinued Operations of $937 million adjusted for noncash charges of $987 million, which principally includes $988 million for Depreciation and Amortization. Changes in Assets and Liabilities represent those items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are a $311 million cash increase from Customer Deposits held for trading activities and increases from Accounts Payable and Accrued Taxes. Cash increased $173 million related to Accounts Payable due to higher fuel and allowance acquisition costs not paid at September 30, 2005. Accrued Taxes increased due to the difference between the recording of the current federal income tax liability, the timing of required estimated payments and the receipt of a prior year federal income tax refund. Our consolidated tax group paid a total of $217 million in federal income taxes, net of refunds, during the first nine months of 2005. We also realized gains on sales of assets of $172 million and made contributions of $306 million to our pension trust fund.

Investing Activities

	Nine Months Ended September 30, 2006	2005
	(in millions)	
Investment Securities:		
Purchases of Investment Securities	$ (8,153)	$ (4,319)
Sales of Investment Securities	8,056	4,378
Change in Investment Securities, Net	(97)	59
Construction Expenditures	(2,445)	(1,610)
Acquisition of Waterford Plant	-	(218)
Change in Other Temporary Cash Investments, Net	20	99
Proceeds from Sales of Assets	120	1,599
Other	(72)	11
Net Cash Flows Used for Investing Activities	$ (2,474)	$ (60)

Net Cash Flows Used For Investing Activities were $2.5 billion in 2006 primarily due to Construction Expenditures supporting our environmental investment plan. These cash flows were consistent with our budgeted cash flows for investing activities for the nine months ended September 30, 2006. We forecast $1.3 billion of Construction Expenditures for the remainder of 2006, which will be funded through results of operations and financing activities.

During 2006, we purchased $8.2 billion of investments and received $8.1 billion of proceeds from the sales of securities. During 2005, we purchased $4.3 billion of investments and received $4.4 billion of proceeds from the sales of securities. In our normal course of business, we purchase taxable and tax exempt securities with cash available for short-term investments. The increased purchases and sales in 2006 reflect our investing in expanded investment security types. These amounts also include purchases and sales within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $60 million in 2005 primarily due to the proceeds from the sale of HPL and STP, a portion of which we used to repurchase common stock and retire senior unsecured notes. Our Construction Expenditures of $1.6 billion included generation, environmental, transmission and distribution investment.

We forecast $3.5 billion of construction expenditures for 2007, which will be funded through results of operations and financing activities. These 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, legal reviews and the ability to access capital.

Financing Activities

	Nine Months Ended September 30, 2006	2005
	(in millions)	
Issuance of Common Stock	$ 24	$ 393
Repurchase of Common Stock	-	(427)
Issuance/Retirement of Debt, Net	529	(562)
Dividends Paid on Common Stock	(437)	(408)
Other	3	(106)

Net Cash Flows From (Used for) Financing Activities	$	119	$	(1,110)

Net Cash Flows From Financing Activities in 2006 were $119 million. During 2006, we issued $115 million of new obligations relating to pollution control bonds, issued $1 billion of senior unsecured notes and retired $396 million of senior unsecured notes for a net increase in senior unsecured notes outstanding of $604 million and retired $100 million of first mortgage bonds and $52 million of securitization bonds. See Note 13 for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used For Financing Activities in 2005 were $1.1 billion. During 2005, we repurchased common stock and reduced outstanding long-term debt using the proceeds from the sale of HPL and the conversion of the equity units to common stock. In addition, our subsidiaries retired $66 million of cumulative preferred stock, which is reflected in the Other amount in the above table. In addition to the equity unit conversion, we had limited stock issuances related to stock options exercised.

Off-balance Sheet Arrangements

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. Our significant off-balance sheet arrangements changed from year-end as follows:

		September 30, 2006		December 31, 2005
		(in millions)		
AEP Credit	$	548	$	516
Rockport Plant Unit 2		2,437		2,511
Railcars		31		31

For complete information on each of these off-balance sheet arrangements see the "Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2005 Annual Report.

Summary Obligation Information

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

Other

Cook Plant Outage

In September 2006, Cook Plant Unit 1 began a regular scheduled refueling outage. This outage includes the replacement of major components, including the reactor vessel head. Installation of capital projects exceeding $100 million will be completed during this outage and were included in our capital forecast. The improvements and replacement of major components should increase unit capacity and efficiency. We expect to restart Cook Plant Unit 1 in early November 2006 as planned. We refueled Cook Plant Unit 2 during March and April 2006 and plan to replace its vessel head during its next refueling outage in 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 March of 2006, we received a $70 million payment for our share in earnings for 2005. The payment for 2006 is contingent on Centrica's future operating results, contractually capped at $20 million and, to the extent earned, is expected to be received and recorded in the first quarter of 2007.

New Generation

In September 2005, PSO sought proposals for new peaking generation to be online in 2008 and in December 2005 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 neutral third parties. 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 PSO 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) 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. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion.

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 the existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new base load coal plant by 2011 in Hempstead County, Arkansas to meet the longer-term generation needs of its customers. Preliminary cost estimates for the new facilities are approximately $1.4 billion (this total excludes the related transmission investment).

The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Annual Report on Form 10-K included cost estimates for these new facilities. All new generation construction projects discussed above are subject to regulatory approvals from the various states in which the subsidiaries operate. Construction is expected to begin in 2007.

SIGNIFICANT FACTORS

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

ERCOT Transmission Project

In October 2006, we announced our intent to form a joint venture company to fund, own and operate new electric transmission assets in ERCOT and we signed a memorandum of understanding with MidAmerican Energy Holdings Co. (MidAmerican) as our joint venture partner. We will contribute Texas transmission assets currently under construction valued at approximately $100 million to the joint venture company. A MidAmerican subsidiary would make a cash contribution to the joint venture company. The equity ownership of the new company would be split 50-50 between AEP and MidAmerican with an anticipated utility capitalization structure targeted at 40 percent equity and 60 percent debt. The joint venture is anticipated to be active in 2007 and is subject to regulatory approval from the PUCT and the FERC.

We believe there is a high degree of regulatory certainty for transmission investment due to the predetermination of ERCOT's need based on significant Texas economic growth as well as "green generation" initiatives. In addition, a streamlined annual interim transmission cost of service review process is available, which will help reduce regulatory lag. The use of a joint venture structure will allow us to reduce its up-front capital requirements for this type of significant investment while allowing us to participate in more 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 peak transfer capability by approximately 5,000 MW and reducing transmission line losses by up to 280 MW. It will 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 be shared with other third party participants. The project is subject to PJM, state and federal regulatory approvals and appropriate incentive cost recovery mechanisms. The projected in-service date is 2014, assuming three years to site and acquire rights-of-way and five years to construct the line. We were the first to file with the Department of Energy (DOE) seeking to have the proposed route designated 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 Electric Transmission Congestion Study". In this study, DOE indicated that the mid-Atlantic Coastal area, where the AEP Interstate Project is designed to reinforce, is one of the two most critical congestion areas in the nation. This finding should help AEP to obtain early National Interest Transmission Corridor Designation as promulgated by the National Energy Policy Act of 2005. In October 2006, both AEP and PJM filed comments with the DOE encouraging corridor designation that is consistent with the proposed line.

In July 2006, the FERC granted conditional approval for incentive rate treatment for the proposed line. The approval is conditioned upon the new line being included in PJM's formal Regional Transmission Expansion Plan to be finalized later this year or in early 2007. The approved incentives include, (a) a return on equity set at the high end of the "zone of reasonableness"; (b) the option to timely recover the cost of capital associated with construction work in progress; and (c) the ability to defer expense and recover costs incurred during the pre-construction and pre-operating period. Since the FERC approved these rate making principles, we expect to implement the incentives in future FERC rate filings.

Texas Regulatory Activity

Texas Restructuring

In June 2006, TCC filed to implement a CTC refund of $357 million for its other true-up items over eight years. The differences between the components of TCC's Recorded Net Regulatory Liabilities **-** Other True-up Items as of September 30, 2006 (including interest) and its Net CTC Refund Proposed request are detailed below**:**

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		31
Retail Clawback including Carrying Costs		(65)
Deferred Over-recovered Fuel Balance		(184)
Retrospective ADFIT Benefit		(77)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(238)
Unrecorded Prospective ADFIT Benefit		(240)

Gross CTC Refund Proposed		(478)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		98
Net CTC Refund Proposed, After Deferrals		(364)
True-up Proceeding Expense Surcharge		7
Net CTC Refund Proposed, After Deferrals and Expenses	$	(357)

In September 2006, the PUCT approved an interim CTC that was implemented on October 12, 2006, the same day that TCC began billing customers for the securitization bonds. The interim CTC will refund the entire retail clawback of $65 million (including carrying costs) by the end of 2006 to residential customers. The CTC refund to the other customer classes during the interim period will be as proposed by TCC, with the exception of the large industrials, who will not receive any fuel refunds during the interim period.

At an October 2006 open meeting, the PUCT announced oral decisions regarding the CTC refund. A final written order is expected in late November or early December of this year. In its decision, the PUCT confirmed that TCC can use securitization bond proceeds to make the CTC refund. The PUCT's decision was to continue the interim CTC through December 2006 to complete the refund of the retail clawback over three months. Beginning in January 2007, the Deferred Over-recovered Fuel Balance will be refunded over six months with the large industrial customers receiving their entire refund in January 2007. Starting in July 2007, the remaining CTC items will be refunded over one year, except that the PUCT agreed with TCC's request to defer the refund of the ADITC and EDFIT Benefit Refund Deferral and the FERC Jurisdictional Fuel Refund Deferral (see table above). The PUCT will decide those issues and related amounts in another proceeding.

Municipal customers and other intervenors appealed the PUCT orders seeking to further reduce TCC's true-up recoveries. If we determine, as a result of future PUCT orders or appeal court rulings, that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC appealed the PUCT orders seeking relief in both state and federal court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- the PUCT ruled that TCC did not comply with the statute and PUCT rules regarding the auction of 15% of its Texas jurisdictional installed capacity,
- 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 gas units with the sale of its coal unit,
- and two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects TCC's deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of $104 million of TCC's ADITC and the loss by TCC of future accelerated tax depreciation election. The estimated future impact on earnings of the Texas Restructuring as of September 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves TCC's CTC filing, including the interim refund, is detailed below:

	(in millions)	
ADITC and EDFIT Benefits Reducing Securitization	$	98
ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets		(60)

Securitization Settlement		(77)
Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund		(240)
Unrecorded Equity Carrying Costs Recognized as Collected		224
Future Interest Payable on Proposed CTC Refund		(19)
Deferred Fuel - Federal Jurisdictional Issue		16
Net Adverse Earnings Impact Over 14 Years	$	(58)

If the PUCT changes its oral decision regarding the proposed CTC deferral and the two contingent federal matters are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to $181 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the $2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of $797 million and from the $1.74 billion sale of securitization bonds in October 2006 less the proposed $357 million CTC refund over the next eight years.

Litigation

In the ordinary course of business, we and our subsidiaries are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring, Note 7 - Commitments and Contingencies and the “Litigation” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2005 Annual Report. Additionally, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies included herein. Adverse results in these proceedings have the potential to materially affect the results of operations, cash flows and financial condition of AEP and its subsidiaries.

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

Environmental Matters

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

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

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

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 environmental intervenor groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and 2000 against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has 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 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 exclude most of the challenged activities from NSR.

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

Critical Accounting Estimates

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

Adoption of New Accounting Pronouncements

Beginning in 2006, we adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based awards, 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 September 30, 2006, we have $49.1 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 1.57 years. See Note 2 - New Accounting Pronouncements in our Condensed Notes to Condensed Consolidated Financial Statements for further discussion.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, our Utility Operations segment is exposed to certain market risks. These risks include commodity price risk, interest rate risk and credit risk. In addition, 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.

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

We employ risk management contracts including physical forward purchase and sale contracts, exchange traded futures and options, over-the-counter options, swaps and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas, coal, and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is controlled by commercial operations, our Chief Risk Officer and risk management staff. When commercial activities exceed predetermined limits, the positions are modified 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 have embraced the disclosure standards applicable to our business activities. The following tables provide information on our risk management activities.

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

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of September 30, 2006 and the reasons for changes in our total MTM value included in our condensed balance sheet as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
September 30, 2006
(in millions)

	Utility Operations	Investments - Gas Operations	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	$ 444	$ 99	$ 543	$ 26	$ 569
Noncurrent Assets	337	130	467	4	471
Total Assets	781	229	1,010	30	1,040
Current Liabilities	(373)	(99)	(472)	(24)	(496)
Noncurrent Liabilities	(184)	(137)	(321)	(3)	(324)
Total Liabilities	(557)	(236)	(793)	(27)	(820)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 224	$ (7)	$ 217	$ 3	$ 220

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2006
(in millions)

	Utility Operations	Investments-Gas Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2005	$ 215	$ (19)	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(8)	10	2
Fair Value of New Contracts at Inception When Entered During the Period (a)	1	-	1
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	(1)	-	(1)
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)	19	2	21
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(3)	-	(3)
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2006	$ 224	$ (7)	217
Net Cash Flow and Fair Value Hedge Contracts			3
Ending Net Risk Management Assets at September 30, 2006			$ 220

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(b)

Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions. Approximately $7 million of the regulatory deferral 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 3.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of September 30, 2006
(in millions)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ -	$ (9)	$ 22	$ (1)	$ -	$ -	$ 12
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(4)	119	29	23	-	-	167
Prices Based on Models and Other Valuation Methods (b)	(1)	(15)	5	19	28	9	45
Total	$ (5)	$ 95	$ 56	$ 41	$ 28	$ 9	$ 224
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ -	$ 7	$ -	$ -	$ -	$ -	$ 7
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(2)	(4)	-	-	-	-	(6)
Prices Based on Models and Other Valuation Methods (b)	-	-	(2)	(4)	(3)	1	(8)
Total	$ (2)	$ 3	$ (2)	$ (4)	$ (3)	$ 1	$ (7)
Total:							
Prices Actively Quoted - Exchange Traded Contracts	$ -	$ (2)	$ 22	$ (1)	$ -	$ -	$ 19
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(6)	115	29	23	-	-	161
Prices Based on Models and Other Valuation Methods (b)	(1)	(15)	3	15	25	10	37
Total	$ (7)	$ 98	$ 54	$ 37	$ 25	$ 10	$ 217

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

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 September 30, 2006

Commodity	**Transaction Class**	**Market/Region**	**Tenor (in Months)**
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	18
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	18
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East	39
	Physical Forwards	AEP West	39
	Physical Forwards	West Coast	39
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	27
Coal	Physical Forwards	PRB, NYMEX, CSX	27

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2005 to September 30, 2006. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as effective cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Nine Months Ended September 30, 2006
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance in AOCI, December 31, 2005	$ (6)	$ (21)	$ (27)
Changes in Fair Value	13	(3)	10
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	7	1	8
Ending Balance in AOCI, September 30, 2006	$ 14	$ (23)	$ (9)
After-Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 15	$ (2)	$ 13

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of September 30, 2006, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 2.56%, expressed in terms of net MTM assets and net receivables. As of September 30, 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	$ 802	$ 140	$ 662	1	$ 70
Split Rating	4	4	-	1	-
Noninvestment Grade	15	15	-	2	-
No External Ratings:					
Internal Investment Grade	33	-	33	3	21
Internal Noninvestment Grade	40	22	18	3	17
Total as of September 30, 2006	$ 894	$ 181	$ 713	10	$ 108
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, 2008. This table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. “Estimated Plant Output Hedged” represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of September 30, 2006

	Remainder 2006	2007	2008
Estimated Plant Output Hedged	91%	88%	87%

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 September 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

Nine Months Ended September 30, 2006 (in millions)	Twelve Months Ended December 31, 2005 (in millions)

End	High	Average	Low	End	High	Average	Low
$2	$10	$3	$1	$3	$5	$3	$1

The High VaR for the nine months ended September 30, 2006 occurred in mid-August during a period of high gas and power price 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 $550 million at September 30, 2006 and $615 million at December 31, 2005. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2006 and 2005
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2006	2005	2006	2005
REVENUES				
Utility Operations	$ 3,485	$ 3,152	$ 9,282	$ 8,437
Gas Operations	(47)	73	(80)	449
Other	156	103	436	326
TOTAL	3,594	3,328	9,638	9,212
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,113	1,066	2,962	2,659
Purchased Energy for Resale	267	181	670	494
Purchased Gas for Resale	4	5	4	255
Maintenance and Other Operation	904	873	2,634	2,588
Gain/Loss on Disposition of Assets, Net	-	(1)	(68)	(116)
Asset Impairments and Other Related Charges	209	39	209	39
Depreciation and Amortization	376	336	1,065	988
Taxes Other Than Income Taxes	186	205	567	566
TOTAL	3,059	2,704	8,043	7,473
OPERATING INCOME	535	624	1,595	1,739
Interest and Investment Income	22	18	41	43
Carrying Costs Income	3	27	66	83
Allowance For Equity Funds Used During Construction	12	5	25	17
Gain on Disposition of Equity Investments, Net	-	56	3	56
Investment Value Losses	-	(7)	-	(7)
INTEREST AND OTHER CHARGES				
Interest Expense	174	163	518	524
Preferred Stock Dividend Requirements of Subsidiaries	1	1	2	6
TOTAL	175	164	520	530
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	397	559	1,210	1,401
Income Tax Expense	133	196	394	471

Minority Interest Expense		1		1		2		3
Equity Earnings of Unconsolidated Subsidiaries		2		3		1		10
INCOME BEFORE DISCONTINUED OPERATIONS		265		365		815		937
DISCONTINUED OPERATIONS, Net of Tax		-		22		6		26
NET INCOME	$	265	$	387	$	821	$	963
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		394		389		394		389
BASIC EARNINGS PER SHARE								
Income Before Discontinued Operations	$	0.67	$	0.94	$	2.07	$	2.41
Discontinued Operations, Net of Tax		-		0.05		0.01		0.07
TOTAL BASIC EARNINGS PER SHARE	$	0.67	$	0.99	$	2.08	$	2.48
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		396		390		396		390
DILUTED EARNINGS PER SHARE								
Income Before Discontinued Operations	$	0.67	$	0.94	$	2.06	$	2.40
Discontinued Operations, Net of Tax		-		0.05		0.01		0.07
TOTAL DILUTED EARNINGS PER SHARE	$	0.67	$	0.99	$	2.07	$	2.47
CASH DIVIDENDS PAID PER SHARE	$	0.37	$	0.35	$	1.11	$	1.05

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2006 and December 31, 2005
(in millions)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 259	$ 401
Other Temporary Cash Investments	198	127
Accounts Receivable:		
Customers	751	826
Accrued Unbilled Revenues	314	374
Miscellaneous	52	51
Allowance for Uncollectible Accounts	(34)	(31)
Total Receivables	1,083	1,220
Fuel, Materials and Supplies	810	726
Risk Management Assets	569	926
Margin Deposits	90	221
Regulatory Asset for Under-Recovered Fuel Costs	66	197
Other	100	127
TOTAL	3,175	3,945
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,712	16,653
Transmission	6,952	6,433
Distribution	11,179	10,702
Other (including coal mining and nuclear fuel)	3,277	3,116
Construction Work in Progress	2,848	2,217
Total	40,968	39,121
Accumulated Depreciation and Amortization	15,146	14,837
TOTAL - NET	25,822	24,284
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,196	3,262
Securitized Transition Assets and Other	558	593
Spent Nuclear Fuel and Decommissioning Trusts	1,191	1,134
Investments in Power and Distribution Projects	45	97
Goodwill	76	76
Long-term Risk Management Assets	471	886
Employee Benefits and Pension Assets	1,059	1,105
Other	682	746
TOTAL	7,278	7,899
Assets Held for Sale	110	44
TOTAL ASSETS	$ 36,385	$ 36,172

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2006 and December 31, 2005
(Unaudited)

			2006		**2005**
CURRENT LIABILITIES			**(in millions)**		
Accounts Payable		$	1,180	$	1,144
Short-term Debt			23		10
Long-term Debt Due Within One Year			1,789		1,153
Risk Management Liabilities			496		906
Accrued Taxes			828		651
Accrued Interest			192		183
Customer Deposits			336		571
Other			752		842
TOTAL			5,596		5,460
NONCURRENT LIABILITIES					
Long-term Debt			10,974		11,073
Long-term Risk Management Liabilities			324		723
Deferred Income Taxes			4,673		4,810
Regulatory Liabilities and Deferred Investment Tax Credits			2,955		2,747
Asset Retirement Obligations			975		936
Employee Benefits and Pension Obligations			349		355
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2			150		157
Deferred Credits and Other			803		762
TOTAL			21,203		21,563
TOTAL LIABILITIES			26,799		27,023
Cumulative Preferred Stock Not Subject to Mandatory Redemption			61		61
Commitments and Contingencies (Note 5)					
COMMON SHAREHOLDERS' EQUITY					
Common Stock Par Value $6.50:					
	2006	2005			
Shares Authorized	600,000,000	600,000,000			
Shares Issued	415,979,691	415,218,830			
(21,499,992 shares were held in treasury at September 30, 2006 and December 31, 2005)			2,704		2,699
Paid-in Capital			4,153		4,131
Retained Earnings			2,669		2,285
Accumulated Other Comprehensive Income (Loss)			(1)		(27)
TOTAL			9,525		9,088
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY		$	36,385	$	36,172

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2006 and 2005
(in millions)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 821	$ 963
Less: Discontinued Operations, Net of Tax	(6)	(26)
Income Before Discontinued Operations	815	937
Adjustments for Noncash Items:		
Depreciation and Amortization	1,065	988
Accretion of Asset Retirement Obligations	47	50
Deferred Income Taxes	(88)	(33)
Deferred Investment Tax Credits	(20)	(23)
Asset Impairments, Investment Value Losses and Other Related Charges	209	46
Carrying Costs Income	(66)	(83)
Mark-to-Market of Risk Management Contracts	(21)	-
Amortization of Nuclear Fuel	38	42
Deferred Property Taxes	105	94
Pension Contributions to Qualified Plan Trusts	-	(306)
Fuel Over/Under-Recovery, Net	158	(183)
Gain on Sales of Assets and Equity Investments, Net	(71)	(172)
Change in Other Noncurrent Assets	72	(84)
Change in Other Noncurrent Liabilities	(21)	34
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	139	5
Fuel, Materials and Supplies	(84)	54
Accounts Payable	(49)	173
Accrued Taxes	176	118
Customer Deposits	(235)	311
Other Current Assets	142	(246)
Other Current Liabilities	(98)	(23)
Net Cash Flows From Operating Activities	2,213	1,699
INVESTING ACTIVITIES		
Construction Expenditures	(2,445)	(1,610)
Acquisition of Waterford Plant	-	(218)
Change in Other Temporary Cash Investments, Net	20	99
Purchases of Investment Securities	(8,153)	(4,319)
Sales of Investment Securities	8,056	4,378
Proceeds from Sales of Assets	120	1,599
Other	(72)	11
Net Cash Flows Used For Investing Activities	(2,474)	(60)
FINANCING ACTIVITIES		
Issuance of Common Stock	24	393
Repurchase of Common Stock	-	(427)
Change in Short-term Debt, Net	11	(8)
Issuance of Long-term Debt	1,229	2,045

Retirement of Long-term Debt		(711)		(2,599)
Dividends Paid on Common Stock		(437)		(408)
Other		3		(106)
Net Cash Flows From (Used For) Financing Activities		119		(1,110)
Net Increase (Decrease) in Cash and Cash Equivalents		(142)		529
Cash and Cash Equivalents at Beginning of Period		401		320
Cash and Cash Equivalents at End of Period	$	259	$	849
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	462	$	492
Net Cash Paid for Income Taxes		206		277
Noncash Acquisitions Under Capital Leases		66		42
Construction Expenditures Included in Accounts Payable at September 30,		334		182
Disposition of Liabilities Related to Acquisitions/Divestitures, Net		-		20

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2006 and 2005
(in millions)
(Unaudited)

	Common Stock				Accumulated Other Comprehensive	
	Shares	Amount	Paid-in Capital	Retained Earnings	Income (Loss)	Total
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515
Issuance of Common Stock	10	65	328			393
Common Stock Dividends				(408)		(408)
Repurchase of Common Stock			(427)			(427)
Other			17			17
TOTAL						8,090
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 $36					(67)	(67)
Minimum Pension Liability, Net of Tax of $0					4	4
Securities Available for Sale, Net of Tax of $0					1	1
NET INCOME				963		963
TOTAL COMPREHENSIVE INCOME						895
SEPTEMBER 30, 2005	415	$ 2,697	$ 4,121	$ 2,579	$ (412)	$ 8,985
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088
Issuance of Common Stock	1	5	19			24
Common Stock Dividends				(437)		(437)
Other			3			3
TOTAL						8,678
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Cash Flow Hedges, Net of Tax of $10					18	18
Securities Available for Sale, Net of Tax of $4					8	8
NET INCOME				821		821
TOTAL COMPREHENSIVE INCOME						847
SEPTEMBER 30, 2006	416	$ 2,704	$ 4,153	$ 2,669	$ (1)	$ 9,525

See Condensed Notes to Condensed Consolidated Financial Statements.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed consolidated financial statements and footnotes were prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission (SEC). Accordingly, they do not include all the information and footnotes required by GAAP for complete financial statements.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods. The results of operations for the three and nine months ended September 30, 2006 are not necessarily indicative of results that may be expected for the year ending December 31, 2006. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2005 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2005 as filed with the SEC on March 1, 2006.

Components of Accumulated Other Comprehensive Income (Loss)

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

Components	September 30, 2006	December 31, 2005
	(in millions)	
Securities Available for Sale, Net of Tax	$ 27	$ 19
Cash Flow Hedges, Net of Tax	(9)	(27)
Minimum Pension Liability, Net of Tax	(19)	(19)
Total	$ (1)	$ (27)

At September 30, 2006, we expect to reclassify approximately $13 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 September 30, 2006, thirty-nine 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

At September 30, 2006, we have options outstanding under two stock-based employee compensation plans: The Amended and Restated American Electric Power System Long-Term Incentive Plan and the Central and South West Corporation Long-Term Incentive Plan. We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees, in accordance with plans previously approved by shareholder votes.

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

In conjunction with the adoption of SFAS 123R, we changed our method of attributing the value of stock-based compensation to expense from the accelerated multiple-option approach to the straight-line single-option method. Compensation expense for all share-based payment awards granted prior to January 1, 2006 will continue to be recognized using the accelerated multiple-option approach while compensation expense for all share-based payment awards granted on or after January 1, 2006 is recognized using the straight-line single-option method. As stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three and nine months periods ended September 30, 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In our pro forma information presented below as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the three and nine months ended September 30, 2005, no stock option expense was reflected in Net Income as we accounted for stock options using the intrinsic value method under Accounting Principles Board (APB) Opinion No. 25, "Accounting For Stock Issued to Employees." Under the intrinsic value method, no stock option expense is recognized when the exercise price of the stock options granted equals the fair value of the underlying stock at the date of grant. During the first nine months of 2005 the Board of Directors granted 10,000 options. For the three and nine months ended September 30, 2006 and 2005, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units. See Note 10 for additional discussion.

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

The following table shows the effect on our Net Income and Earnings Per Share as if we had applied fair value measurement and recognition provisions of SFAS 123 to stock-based employee and director compensation awards for the three and nine months ended September 30, 2005:

	Three Months Ended		Nine Months Ended	
	(in millions, except per share data)			
Net Income, As Reported	$	387	$	963
Add: Stock-based Compensation Expense Included in Reported Net Income, Net of Related Tax Effects		4		10
Deduct: Stock-based Compensation Expense Determined Under Fair Value Based Method for All Awards, Net of Related Tax Effects		(5)		(11)
Pro Forma Net Income	$	386	$	962
Earnings Per Share:				
Basic - As Reported	$	0.99	$	2.48
Basic - Pro Forma (a)	$	0.99	$	2.48
Diluted - As Reported	$	0.99	$	2.47
Diluted - Pro Forma (a)	$	0.99	$	2.47

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

Earnings Per Share (EPS)

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

	Three Months Ended September 30,					
	2006			2005		
	(in millions, except per share data)					
			$/share			$/share
Earnings applicable to common stock	$ 265			$ 387		
Average number of basic shares outstanding	393.9	$	0.67	388.9	$	0.99
Average dilutive effect of:						
Performance Share Units	2.0		-	1.0		-
Stock Options	0.2		-	0.5		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	-		-
Average number of diluted shares outstanding	396.3	$	0.67	390.5	$	0.99

	Nine Months Ended September 30,					
	2006			2005		
	(in millions, except per share data)					
			$/share			$/share
Earnings applicable to common stock	$ 821			$ 963		
Average number of basic shares outstanding	393.8	$	2.08	388.7	$	2.48
Average dilutive effect of:						
Performance Share Units	1.6		(0.01)	0.9		(0.01)
Stock Options	0.2		-	0.3		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	-		-
Average number of diluted shares outstanding	395.8	$	2.07	390.0	$	2.47

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

Related Party Transactions

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
AEP Consolidated Purchased Energy:				
Ohio Valley Electric Corporation (43.47% Owned)	$ 54	$ 49	$ 167	$ 140

Sweeny Cogeneration Limited Partnership (50% Owned)	30	38	92	98
AEP Consolidated Other Revenues - Barging and Other Transportation Services - Ohio Valley Electric Corporation (43.47% Owned)	8	6	23	14

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on our previously reported results of operations, financial condition or changes in shareholders' equity.

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

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

In December 2004, the FASB issued SFAS 123R. SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." We recorded an insignificant cumulative effect of a change in accounting principle in the first quarter of 2006 for the effect of initially applying the statement primarily reflected in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

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

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards granted after the time of adoption and recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost is based on the grant-date fair value of the equity award. Stock-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2006 includes compensation expense for share-based payment awards granted prior to, but not yet vested as of, January 1, 2006 based on the grant date fair value estimated in accordance with the pro forma provisions of SFAS 123 and compensation expense for the share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS 123R. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

SFAS 157 "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157. SFAS 157 enhances existing guidance for fair value measurement of assets and liabilities as well as instruments measured at fair value that are classified in shareholders' equity. SFAS 157 defines fair value, establishes a fair value measurement framework and expands fair value disclosures. SFAS 157 emphasizes that fair value is market-based with the highest measurement hierarchy being market prices in active markets. The standard will change current practice and requires fair value measurements be disclosed by hierarchy level. SFAS 157 requires 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 are currently in the process of determining the effect this standard will have on our financial statements. Although SFAS 157 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. SFAS 157 will be effective for us starting January 1, 2008.

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

In September 2006, the FASB issued SFAS 158. SFAS 158 amends previous standards. It requires employers to fully recognize the obligations associated with defined benefit pension, retiree healthcare and other postretirement (OPEB) plans 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 its 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 SFAS 87, "Employers' Accounting for Pensions," or SFAS 106, "Employer's Accounting for Postretirement Benefits Other Than Pensions." It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit postretirement plan affects net periodic benefit costs for the next fiscal year.

The effect of SFAS 158 is to adjust AOCI at the end of each year, for both underfunded and overfunded pension and OPEB plans, to an amount equal to the remaining unrecognized SFAS 87 and SFAS 106 deferrals for unamortized actuarial losses or gains, prior service costs, or 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.

SFAS 158 is effective for initial recognition of a defined benefit postretirement plan and related disclosure for fiscal years ending after December 15, 2006. We have not completed the process of determining the effect of this standard on our financial statements, including whether a portion of the adjustment required by SFAS 158 can be deferred as a regulatory asset under SFAS 71.

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 pursuant to APB Opinion No. 22, "Disclosure of Accounting Policies." 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.

EITF 06-3 is effective for fiscal years beginning after December 15, 2006. As disclosed in Note 1 of the 2005 Annual Report, 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 and we do not recognize these taxes as revenues or expenses. Therefore, this issue will not have a material impact on our financial statements.

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

In July 2006, the FASB issued FIN 48 which clarifies the application of SFAS 109, "Accounting for Income Taxes." FIN 48 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 have not completed the process of determining the effect of this interpretation on 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. SAB 108 addresses the diversity in practice when quantifying the effect of an error on financial statements. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying misstatements in current year financial statements. We will be required to adopt the provisions of SAB 108 effective December 31, 2006. We believe that the adoption of SAB 108 will 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, 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.

3. RATE MATTERS

As discussed in our 2005 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. The Rate Matters note within our 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations and cash flows. Rate matters that are not believed to be reasonably likely to affect future results of operations and cash flows are not included in this report or the 2005 Annual Report. The following sections discuss ratemaking developments in 2006 and update the 2005 Annual Report.

APCo Virginia Environmental and Reliability Costs

The Virginia Electric Restructuring Act (the statute) 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 2004 through September 2005. Through August 31, 2006, APCo deferred as a regulatory asset $47 million of incremental E&R costs incurred since July 1, 2004 based on a legal opinion that such costs were probable of recovery under the law.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to increase its electric rates at an ongoing level of $20 million to recover current, rather than past, incremental E&R costs. The staff proposal would effectively disallow the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that were deferred as a regulatory asset. At the E&R hearings, which concluded in March 2006, the staff amended its testimony to recommend a $24 million increase in APCo’s ongoing rates. In September 2006, the Hearing Examiner issued a report recommending adoption of the staff proposal with minor modifications, which would result in (a) an on-going level of E&R cost recovery of $29 million only if the Virginia SCC decides that any rate increase from the base rate case (described below) does not include the $29 million ongoing level of E&R costs, and (b) the disallowance of all previously deferred incremental E&R costs. In the third quarter of 2006, we concluded that the Virginia SCC might not grant recovery of actual incremental E&R costs incurred during the period from July 2004 through September 2006. Accordingly, we wrote off all of the E&R regulatory asset, adversely affecting pretax earnings by $36 million, net of the reinstatement of related AFUDC and capitalized interest. We believe that the staff’s proposal and the Hearing Examiner’s recommendation are contrary to the statute. The Virginia SCC’s final order in this proceeding is pending.

If the Virginia SCC properly implements the statute as interpreted in its October 2005 order and as supported by the Virginia Attorney General’s office in October 2006, we should be able to recover all of our incremental E&R costs prudently incurred since July 1, 2004. If the Virginia SCC adopts the Hearing Examiner's findings, based on advice of counsel, we will appeal the decision.

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 adjusted annually. APCo also proposed to share the off-system sales margins with the customers with 40% going to reduce rates and 60% being retained by APCo. This resultant 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 revenues of $198 million. The major components of the $225 million 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 October 2, 2006, subject to refund. In October 2006, the Virginia SCC staff filed their direct testimony recommending a base rate increase of $13 million. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. APCo plans to file rebuttal testimony in November 2006. Hearings are scheduled to begin in December 2006. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

APCo and WPCo West Virginia Rate Case

In July 2006, the WVPSC approved the settlement agreement APCo and WPCo reached with the WVPSC staff and intervenors in the 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;
- 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 Condensed Consolidated Balance Sheets, which will impact cash flows but not earnings.

In addition, the agreement provides a surcharge mechanism that allows APCo and WPCo to adjust their rates 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. Although the amount of these annual surcharge increases cannot be determined until the incremental costs are known and reviewed by the WVPSC, APCo estimates that they will result in an annual increase in revenues of $36 million effective July 1, 2007, $14 million effective July 1, 2008 and $18 million effective July 1, 2009.

The settlement further provides for the reinstatement of the ENEC mechanism effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel and purchased power 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 on the unrefunded balance in future ENEC proceedings.

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. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately $69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook 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. A public hearing was held in May 2006 and the final brief was filed in June 2006. As proposed by I&M, the book depreciation expense reduction would increase earnings, but would not impact cash flows until electric service rates are revised.

An order issued by the IURC on October 19, 2006 does not dispute our revised depreciation accounting rates but, nevertheless, the IURC denied I&M's request to revise its book depreciation rates between base rate cases. The IURC believes that depreciation rates for an electric utility should not be changed between general rate cases unless it was “absolutely essential” and a direct benefit to customers was shown. I&M has twenty days in which to file for a rehearing or reconsideration. We have not yet decided whether we will file for a rehearing or reconsideration or if and when we will file to adjust base rates to reflect the depreciation study.

KPCo Rate Filing

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

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

In 2002, PSO under-recovered $44 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the 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 through 2003 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with their proposed reallocation of off-system sales margins of $27 million to $37 million 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.

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

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 existed during the year. A hearing was held in August 2006 and we expect a recommendation from the ALJ in the fourth quarter of 2006.

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. The OCC staff indicated that it expects the review process to begin in late 2006 or early 2007.

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 September 2006, PSO filed a notice of its intent to file in November 2006 a plan to modify the base rates of PSO's Oklahoma jurisdictional customers with a proposed effective date in the second quarter of 2007.

SWEPCo Louisiana Fuel Inquiry

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

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported the results of its review of SWEPCo's year-end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff 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 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. In April 2004, at the request of the LPSC, SWEPCo filed updated financial information with a test year ending December 31, 2003. Both filings indicated that SWEPCo's rates should not be reduced. 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 and the recommended base rate reduction does not include the impact of a proposed consolidated federal income tax adjustment, which, if approved, would increase the proposed rate reduction. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. Hearings are expected to occur late in the fourth quarter of 2006. A decision is not expected until 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.

TCC and TNC Rate Filings

In September 2006, we announced that TCC and TNC will each file transmission and distribution wires rate cases in Texas in late 2006. We anticipate requesting an $83 million annual increase for TCC and a $25 million annual increase for TNC. Both requests include the impact of the expiration of the CSW merger savings credits.

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

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

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. Total amortization related to such costs was $1 million in both the third quarter of 2006 and 2005. In the first nine months of 2006 and 2005, total amortization related to such costs was $4 million and $3 million, respectively. As of September 30, 2006 and December 31, 2005, the AEP East companies had $30 million and $31 million, respectively, of deferred 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 of $2 million per year. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone. 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 PJM-billed integration costs, including related carrying charges, of AEP, Commonwealth Edison Company (ComEd) and The Dayton Power & Light Company (DP&L) 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 and KPCo recover the amortization of RTO formation/integration costs billed to the AEP East companies in Ohio and Kentucky. APCo received approval to include the amortization of RTO formation/integration costs in retail rates in West Virginia effective July 28, 2006. In Virginia, APCo filed a base rate case, which includes recovery of these costs when rates became effective October 2, 2006, subject to refund. 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.

Until I&M can adjust its retail rates in Indiana and Michigan to recover the amortization of its deferred RTO formation/integration costs, results of operations and cash flows will be adversely affected by approximately 15% of the amortizations. 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

In accordance with FERC orders, we collected SECA rates to mitigate lost through-and-out transmission service (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 also 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. The AEP East companies recognized gross SECA revenues as follows:

		(in millions)
Three Months Ended September 30, 2006	$	-
Three Months Ended September 30, 2005		43
Nine Months Ended September 30, 2006 (a)		43
Nine Months Ended September 30, 2005		120

(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.

A hearing in the SECA case was held in May 2006 to determine whether any of the SECA revenues should be refunded. 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 were 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 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, and 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. It would also provide refunds of SECA rates paid by the AEP East companies in considerably less significant amounts. Based on the completed settlements, and before the issuance of the ALJ’s initial decision, the AEP East companies provided for $22 million in net refunds, of which $18 million was recorded in the second quarter of 2006 in Utility Operations Revenues on the Condensed Consolidated Statements of Operations.

We, together with Exelon and DP&L, filed an extensive brief noting exceptions to the initial ALJ decision and asking the FERC to reverse the decision in large part. Reply briefs were filed in October 2006. We believe that the FERC should reject the initial ALJ 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. As a result, we have not provided for a possible refund of SECA rates in excess of our current provisions. If the FERC does adopt the ALJ’s recommendations, we will appeal the decision to the courts. 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.

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. We estimate that this rate increase will increase wholesale transmission revenues by $22 million in 2006 and $28 million in 2007.

The Elimination of T&O and SECA Rates and the FERC PJM Regional Transmission Rate Proceeding

In a separate proceeding, at our urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP 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 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 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 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 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 would be just and reasonable alternatives; however, the judge also found the Postage Stamp rate proposed by the FERC staff to be just and reasonable, and recommended it 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 somewhat more revenue for AEP than the AEP/AP proposal, but the phase-in 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 in early to mid-2007.

From the elimination of T&O rates in December 2004 through the expiration of SECA rates on March 31, 2006, SECA transition rates failed to fully compensate the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone was not sufficient to replace the prior T&O revenues or the lower temporary SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the shortfall. Full mitigation of the effects of eliminated T&O revenues and the less favorable terminated SECA revenues will require cost recovery through state retail rate proceedings pending any resolution that may result from the above FERC regional transmission rate proceeding. 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 the FERC-approved OATT which 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 yet filed to seek recovery of the lost transmission revenues.

We presently recover from retail customers approximately 65% of the reduction in transmission revenues of $128 million a year. On October 2, 2006, when new base rates went into effect subject to refund in Virginia, that percentage increased to 80%.

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 Kentucky, Indiana, Virginia and Michigan, the additional transmission revenues can be expected to reduce retail rates in future base rate proceedings.

We believe that the AEP/AP proposal or the Postage Stamp proposal combined with the retail recovery discussed above would be an effective replacement for the eliminated T&O and SECA rates.
Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. Future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues and the resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates in Indiana and Michigan.

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 a small portion of TNC operate in SPP. An ALJ initially ruled against Calpine and we concluded that the likelihood of the FERC awarding Calpine a reactive power capacity rate was remote. In September 2006, the FERC issued its decision reversing the ALJ 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, we recorded an expense provision, including interest, of $8 million in September 2006 for the retroactive reactive power liability. We will seek rehearing at the FERC and may appeal the decision if the FERC either denies rehearing or rules in favor of Calpine on rehearing.

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 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 and CSW Operating Agreement effective May 1, 2006.

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. Our total trading and marketing margins are unaffected by the allocation methodology.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant events occurring in 2006 related to customer choice and industry restructuring and update the 2005 Annual Report.

TEXAS RESTRUCTURING

In February 2006, the PUCT issued an order in TCC's $2.4 billion True-up Proceeding, which determined that TCC's true-up regulatory asset was $1.475 billion including carrying costs through September 2005. In December 2005, TCC adjusted its recorded net true-up regulatory asset to comply with the order. The PUCT issued an order on rehearing in April 2006, which made minor changes to, but otherwise affirmed, the February 2006 order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties appealed the PUCT's true-up order claiming it permits TCC to over-recover stranded generation costs and other true-up items.

TCC Securitization Proceeding

TCC filed an application in March 2006 requesting recovery through securitization of $1.8 billion of net stranded generation plant costs and related carrying costs through August 31, 2006. The $1.8 billion request did not include TCC's negative other true-up items, which total $478 million. See "CTC Proceeding for Other True-up Items" section of this note. Intervenors and the PUCT staff filed testimony regarding TCC's securitization request in April 2006. In May 2006, TCC filed a letter with the PUCT reducing its request by $6 million of current carrying costs and reduced the recorded net recoverable regulatory asset by the recorded debt-related component. In May 2006, TCC and the other parties filed a settlement with the PUCT, which further reduced the securitizable amount by $77 million and settled several issues that would have delayed the sale of the securitization bonds. The PUCT approved the settlement in June 2006 authorizing $1.697 billion including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of $23 million, for a total of $1.72 billion. We issued TCC securitization bonds on October 11, 2006 for $1.74 billion, including additional issuance costs and carrying costs to October 11, 2006.

TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT. We determined that the projected cash flows from the securitization less the proposed CTC refund would be more than sufficient to recover TCC's recorded net true-up regulatory asset due to the existence of $224 million of unrecorded equity-related carrying costs which are not recorded until collected in regulated rates. As a result, no additional impairment was recorded for the approved reduction in the amount to be securitized. However, the $77 million agreed upon reduction in the securitizable amount will have a negative impact on future earnings.

Consistent with certain prior securitization determinations, the PUCT issued a specific order in the securitization proceeding that calculated a $315 million cost-of-money benefit from true-up related ADFIT through August 2006, of which $75 million ($77 million through September 30, 2006) relates to the recorded benefit prior to the date of securitization and $240 million relates to the unrecorded benefit subsequent to the date of securitization. The PUCT included the $315 million ADFIT-related stranded cost benefit in the CTC refund of $478 million. In June 2006, we transferred the effects of the ADFIT on recorded carrying costs from the securitizable asset to the CTC refund, thereby increasing the carrying costs identified to the securitizable assets in the table below.

The differences between the securitization amount ordered by the PUCT of $1.74 billion and the Recorded Securitizable True-up Regulatory Asset of $1.57 billion by component at September 30, 2006 are detailed in the table below:

		(in millions)
Stranded Generation Plant Costs	$	974
Net Generation-related Regulatory Asset		249
Excess Earnings		(49)
Recorded Net Stranded Generation Plant Costs		1,174
Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs		400
Recorded Securitizable True-up Regulatory Asset		1,574
Unrecorded But Recoverable Equity Carrying Costs		224
Unrecorded Estimated October 2006 Debt Carrying Costs		3
Unrecorded Excess Earnings, Related Carrying Costs and Other		53
Unrecorded Settlement Reduction		(77)
Reduction for the Present Value of ADITC and EDFIT Benefits		(61)
Approved Securitizable Amount as of October 11, 2006		1,716
Unrecorded Securitization Bond Issuance Costs		24
Amount Securitized on October 11, 2006	$	1,740

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up and securitization orders, the PUCT reduced net stranded generation plant costs 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 generating assets. (See Reduction for the Present Value of ADITC and EDFIT Benefits of $61 million in the table above.) TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions.

TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. The IRS issued its private letter ruling on May 9, 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. TCC informed the PUCT on May 10, 2006 of the adverse ruling, however, the PUCT did not change its order on rehearing. TCC filed an appeal with the PUCT. As discussed below in the "CTC Proceeding for Other True-up Items" section of this note, TCC proposed, and the PUCT agreed, to defer refunding the amount of the present value of its ADITC and EDFIT benefits through its CTC until this normalization issue is resolved upon the IRS issuance of final normalization regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution property, which approximates $104 million as of September 30, 2006 and also a loss of the 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 through the appeal of the PUCT's true-up order and through a CTC deferral.

CTC Proceeding for Other True-up Items

In June 2006, TCC filed to implement a negative CTC to refund its other true-up items over eight years. TCC will incur interest expense on the other true-up regulatory liability balances until it is fully refunded. The principal components of the CTC refund liability are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance.

The differences between the components of TCC's Recorded Net Regulatory Liabilities - Other True-up Items of $238 million as of September 30, 2006 (including interest expense) and its Net CTC Refund Proposed of $357 million are detailed below:

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		31
Retail Clawback including Carrying Costs		(65)
Deferred Over-recovered Fuel Balance		(184)
Retrospective ADFIT Benefit		(77)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(238)
Unrecorded Prospective ADFIT Benefit		(240)
Gross CTC Refund Proposed		(478)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		98
Net CTC Refund Proposed, After Deferrals		(364)
True-up Proceeding Expense Surcharge		7
Net CTC Refund Proposed, After Deferrals and Expenses	$	(357)

TCC requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of $16 million of FERC jurisdictional fuel over-recoveries (discussed below) and $98 million (including carrying costs) related to potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits (discussed above). Under TCC's proposal, (a) if the two contingent federal matters are resolved consistent with the PUCT's treatment, TCC will then refund the $16 million and the $98 million plus carrying costs or (b) if these two issues are not resolved consistent with the PUCT's treatment, the deferred refunds will not be made in order to avoid a normalization violation and the violation of a Federal court order. Management cannot predict the final outcome of this filing.

Although TCC proposed to refund the $357 million over eight years, certain intervenors supported accelerated refunds. In September 2006, the PUCT approved an interim CTC that was implemented on October 12, 2006, the same day that TCC began billing customers for the securitization bonds. The interim CTC will refund the entire retail clawback of $65 million (including carrying costs) to residential customers by the end of 2006. The CTC refund to the other customer classes during the interim period will be as proposed by TCC, with the exception of the large industrials, who will not receive any fuel refunds during the interim period.

At an October 2006 open meeting, the PUCT announced oral decisions regarding the CTC refund. A final written order is expected in late November or early December of this year. In its decision, the PUCT confirmed that TCC can use securitization bond proceeds to make the CTC refund. The PUCT's decision was to continue the interim CTC through December 2006 to complete the refund of the retail clawback over three months. Beginning in January 2007, the Deferred Over-recovered Fuel Balance will be refunded over six months with the large industrial customers receiving their entire refund in January 2007. Starting in July 2007, the remaining CTC items will be refunded over one year, except that the PUCT agreed with TCC's request to defer the refund of the ADITC and EDFIT Benefit Refund Deferral and the FERC Jurisdictional Fuel Refund Deferral (see table above). The PUCT will decide those issues and related amounts in another proceeding.

Fuel Balance Recoveries

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. In August 2006, TCC also received an order from the Federal District Court, Western District of Texas precluding the PUCT from enforcing its ruling regarding the PUCT's reallocation of off-system sales margins in connection with TCC's final fuel reconciliation. The favorable Federal District Court order, if upheld on appeal, could result in reductions to the over-recovered fuel principal balances of $8 million for TNC and $14 million ($16 million with carrying costs) for TCC. The PUCT appealed the TCC and TNC Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the federal court system, the PUCT may file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT or another party were to file a complaint at the FERC that results in the PUCT's decisions being reinstated, it could result in an adverse effect on results of operations and cash flows for the AEP East companies because an unfavorable FERC ruling may result in a 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.

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

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax weighted average cost of capital rate approved in its unbundled cost of service rate proceeding. The recorded embedded debt component of this carrying cost rate is 8.12%. Through September 30, 2006, TCC recorded $400 million of debt-related carrying costs on stranded generation plant costs included in the securitization proceeding. Equity carrying costs of $224 million related to amounts securitized will be recognized in income as collected. TCC will accrue interest expense until its net CTC refund is fully refunded. The interest expense on the net CTC refund totals $9 million and $11 million for the three and nine months ended September 30, 2006, respectively, and is included in Interest Expense on the Condensed Consolidated Statements of Operations.

In June 2006, the PUCT adopted a proposed rule that prospectively changes the interest rate applied to TCC's CTC refund balance. TCC anticipates that the rule change will reduce the rate TCC will pay on its CTC balance from 11.79% to 7.47%. TCC anticipates that the change will reduce its annual refund by approximately $8 million. The rule also provides for adjustments to the rate during subsequent rate case proceedings.

TNC True-up Proceeding

TNC filed a CTC proceeding in August 2005 to establish a rate to refund its net true-up regulatory liability. In December 2005, that proceeding was abated, pending a final ruling from TNC's appeal to the federal court regarding the fuel proceeding (described above). In August 2006, the parties to TNC's CTC proceeding filed a settlement that recommended implementing an interim refund of the true-up regulatory liability totaling $13 million, net of the amounts at issue in the federal court proceeding, over six months beginning in September 2006. In late August 2006, the PUCT approved the settlement and the net refund began in September 2006. TNC accrues interest expense on the unrefunded balance and will continue to do so until the balance is fully refunded.

Excess Earnings

As noted in our 2005 Annual Report, 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 was unlawful under the Texas Restructuring Legislation. 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. Management is unable to predict the ultimate outcome of these proceedings.

Summary

Our recorded securitizable true-up regulatory asset at September 30, 2006 of $1.57 billion, net of the recorded net regulatory liabilities for other true-up items of $238 million, reflects the PUCT's orders in TCC's True-up Proceeding and its securitization proceeding. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in any subsequent proceedings or court rulings, TCC will amortize its total securitizable true-up regulatory asset commensurate with recovery over the 14-year term of the securitized bonds issued in October 2006. If we determine, as a result of future PUCT orders or appeal court rulings, that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. Based on advice of Texas rate counsel, TCC appealed the PUCT orders seeking relief in both state and federal court where TCC believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. Municipal customers and other intervenors also appealed the same PUCT orders seeking to further reduce TCC's true-up recoveries.

Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings or court appeals. If TCC succeeds in future appeals, it could have a material favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, or if the PUCT does not approve TCC's CTC filing as filed and, as a result, causes a normalization violation, it could have a material adverse effect on future results of operations, cash flows and financial condition.

Texas Restructuring - SPP

In August 2006, the PUCT adopted a rule delaying customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo and a small portion of TNC's business operate in SPP. Approximately 3% of TNC's operations are located in the SPP territory, with $13 million in net assets 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) and TNC's customers, facilities and certificated service located in the SPP area to SWEPCo. If this petition is successful, SWEPCo will be our only subsidiary affected by the delay in the SPP area.

OHIO RESTRUCTURING

Rate Stabilization Plans

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo (the Ohio companies). The approved plans in each of 2006, 2007 and 2008 provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the request for additional revenues for specified costs. CSPCo's potential for the additional annual 4% generation rate increases is diminished by approximately three-quarters in 2006 and to a lesser extent in 2007 and 2008 due to the power acquisition rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding and the recovery of pre-construction costs for its share of the jointly-owned IGCC plant (see "IGCC Plant" section of this note below). OPCo's potential for additional annual 4% generation rate increases is diminished in 2006 by approximately one-quarter and to a lesser extent in 2007 due to the recovery of pre-construction costs for its share of the jointly-owned IGCC plant. The RSPs also provide that the Ohio companies can recover in 2006, 2007 and 2008 estimated 2004 and 2005 deferred environmental carrying costs and PJM-related administrative costs and congestion costs net of financial transmission rights (FTR) revenue related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $10 million and $26 million for CSPCo and $20 million and $58 million for OPCo in the third quarter and first nine months of 2006, respectively, from the RSP rate increases net of the amortization of RSP regulatory assets. These increases also include the recognition of equity carrying costs. As of September 30, 2006, unrecognized equity carrying costs from 2004 and 2005, which are recognized over the three-year RSP recovery period totaled $32 million. As of September 30, 2006, the unamortized RSP regulatory assets to be recovered through December 31, 2008 were $43 million.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSPs and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. In DP&L's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In an appeal concerning First Energy companies' RSP, the Ohio Supreme Court held that the PUCO's decision to eliminate the offer to customers of a price determined through competitive bids was unlawful. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies, which also did not include a competitive bid process, and remanded the case to the PUCO for further proceedings, not inconsistent with the decision in the appeal of the First Energy companies' RSP. 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 continued to collect RSP revenues. In accordance with the PUCO directive, in September 2006, CSPCo and OPCo submitted their proposal to provide additional options for customer participation in the electric market.

In the Ohio companies' case, the Ohio Supreme Court did not address any other issues that had been raised on appeal, stating that its decision does 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.

IGCC Plant

In March 2005, the Ohio companies filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposed cost recovery associated with the IGCC plant in three phases: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, 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 in 2006, 2007 and 2008 under their RSPs. Through September 30, 2006, the Ohio companies deferred pre-construction IGCC costs totaling $16 million and recovered $6 million of those costs. We are currently recovering the remaining deferred amounts through June 30, 2007.

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. In its June order, the PUCO indicated 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 June 2006, the Industrial Energy Users - Ohio (IEU), an intervenor in the PUCO proceeding, filed a Complaint for Writ of Prohibition at the Ohio Supreme Court to prohibit the use of the PUCO's authorization by the Ohio companies to enforce the collection of the Phase 1 rates and to prohibit the PUCO from further entertaining any increase in rates for the IGCC project. The Court subsequently granted a PUCO motion to dismiss the Complaint for Writ of Prohibition.

In August 2006, IEU, 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. The Ohio companies, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, future results of operations and cash flows will be adversely affected.

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 with over/under recovery mechanisms. In February 2006, the Ohio companies filed a request with the PUCO to incorporate all transmission costs and rates in their transmission cost recovery riders and institute a two-step increase to reflect the increases in the FERC-approved rates. In the filing, the first increase would be effective April 1, 2006 to reflect the Ohio companies' share of the loss of SECA revenues and the second increase would be effective August 1, 2006 to recover their share of the cost of the new Wyoming-Jacksons Ferry 765 kV line. In May 2006, the PUCO issued an order approving a two-step increase in the transmission cost recovery riders with over/under recovery mechanisms, effective April 1, 2006. The new tariffs were filed with the PUCO and implemented in June 2006.

In October 2006, the Ohio companies filed for initial true-ups under the transmission cost recovery riders' over/under recovery mechanisms. The filings reflect the refund of regulatory liabilities as of September 30, 2006 of $12 million and $16 million for CSPCo and OPCo, respectively, including carrying charges. These over-recoveries were reflected as part of the new transmission cost recovery rider filed to be effective January 2007. We anticipate the net effect of the new transmission cost recovery riders will result in increased cost recoveries over 2005 levels for CSPCo and OPCo of $27 million and $36 million, respectively, in 2006 and $15 million and $16 million, respectively, in 2007.

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 that the Ohio companies were to meet. In July 2006, based on the 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 the $10 million will best be applied.

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately $12 million of such costs, which was approved by the PUCO in August 2006. Effective September 1, 2006, the Ohio companies implemented the storm cost recovery riders, which will continue until they have collected the authorized amounts or one year, whichever is shorter. In September 2006, the Ohio Consumers' Counsel filed a request for rehearing with the PUCO, which was denied in October 2006.

As a result of the above, in September 2006 the Ohio companies recorded regulatory assets of $14 million, favorably affecting earnings.

Ormet

Ormet Primary Aluminum Corporation and Ormet Primary Mill Products Corporation (together, Ormet) was a customer of OPCo until 2000. Beginning in 2000, at Ormet's request, the PUCO authorized a modification of the certified service territories of OPCo and South Central Power Company (SCP), a nonaffiliate, so that Ormet became a customer of SCP. SCP agreed to let Ormet access the electric generation market for the vast majority of its 520 MW load. Ormet filed a request with the PUCO to return to being served by OPCo at the industrial tariff rate. OPCo opposed the request because it would likely require the purchase of capacity and energy from the market at prices above the industrial RSP tariff rate in order to serve Ormet, as well as substantially reduce our ability to sell energy into the wholesale market at the higher market prices.

In June 2006, the PUCO found that SCP was not providing or proposing to provide physically adequate service to Ormet. In October 2006, the PUCO convened a hearing to determine if an electric supplier, other than SCP, should be authorized to serve Ormet's significant load.

Subsequent to the hearing, the Ohio companies together with Ormet, its employees' union and certain other interested parties filed a settlement agreement with the PUCO for approval. The settlement agreement provides for the reallocation of the service territories of CSPCo, OPCo and SCP so that Ormet's Hannibal, Ohio facilities are located in a joint CSPCo/OPCo certified territory effective January 1, 2007. The settlement also provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH paid by Ormet and a to-be-determined market price submitted by management and reviewed by the PUCO. The recovery is accomplished by the amortization to income 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 RSP. The $43 per MWH price for generation services is above the industrial RSP generation tariff but below current market prices.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies defer customer choice implementation costs and related carrying costs in excess of $20 million each. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through September 30, 2006, we incurred $97 million of such costs and deferred $48 million of such costs for probable future recovery in distribution rates. We have not recorded $9 million of equity carrying costs, which are not recognized until collected. Pursuant to the RSPs, recovery of these amounts is subject to PUCO review and is deferred until the next distribution rate filing to change rates after the December 31, 2008 end of the RSP period. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2005 Annual Report, we continue to be involved in various legal matters. The 2005 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in our 2005 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded. 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. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

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

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

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In July 2004, two special interest groups, Sierra Club and Public Citizen, issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at the Welsh Plant. SWEPCo filed a response to the complaint in May 2005. Other preliminary motions have been filed and are pending before the Court.

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

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

Carbon Dioxide (CO_2) Public Nuisance Claims

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

Ontario Litigation

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

OPERATIONAL

Power Generation Facility and TEM Litigation

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

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

In August 2006, we reached an agreement with Dow to sell the Facility to them. We expect the sale to close during the fourth quarter of 2006 following receipt of federal regulatory approvals. Upon closing, we will repay our recorded $525 million lease financing obligation, which is included in Long-term Debt Due Within One Year on our Condensed Consolidated Balance Sheet at September 30, 2006. The approved sale resulted in a third quarter pretax impairment of approximately $209 million (see Note 8).

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

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

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

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

PPA.

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

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. Oral argument is scheduled for December 2006. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms (if our sale of the Facility to Dow does not close) and to the extent we do not fully recover the claimed termination value damages from TEM.

Enron Bankruptcy

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

After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state trial 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 filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to continue to defend against BOA's claims.

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

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

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

In June and July 2006, we held mediation discussions with BOA and Enron concerning these gas disputes. No further discussions are scheduled at this time. Although management is unable to predict the outcome of the remaining lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in Federal District Court, Columbus, Ohio. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2006, plaintiff filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. Briefing of this appeal is scheduled for completion in December 2006.

Natural Gas Markets Lawsuits

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

Cornerstone Lawsuit

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

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 because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the Nevada utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The Nevada utilities' request for a rehearing was denied. The Nevada utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

6. GUARANTEES

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

LETTERS OF CREDIT

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At September 30, 2006, the maximum future payments for all the LOCs are approximately $34 million with maturities ranging from October 2006 to July 2007.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $68 million with maturity dates ranging from February 2007 to February 2012.

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. This guarantee ends upon depletion of reserves and final reclamation is completed. At September 30, 2006, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036. We estimate the cost for final reclamation during the period 2029 through 2036 at approximately $39 million.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. Prior to September 30, 2006, we entered into several sale agreements. The status of certain sales agreements is discussed in Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.1 billion (approximately $1 billion relates to the BOA litigation, see "Enron Bankruptcy" section of Note 5). There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we 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 September 30, 2006, the maximum potential loss for these lease agreements was approximately $54 million ($35 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. At September 30, 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 structure.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a company-wide staffing and budget review in the second quarter of 2005, we identified approximately 500 positions for elimination. Pretax severance benefits expense of $24 million and $4 million was recorded (primarily in Maintenance and Other Operation within the Utility Operations segment) in the second and third quarters of 2005, respectively.

The following table shows the accrual as of December 31, 2005 (reflected primarily in Current Liabilities - Other on our Condensed Consolidated Balance Sheets) and the activity during the first nine months of 2006, which eliminated the accrual as of June 30, 2006:

	Amount (in millions)	
Accrual at December 31, 2005	$	12
Less: Total Payments		8
Less: Accrual Adjustments		4
Accrual at September 30, 2006	$	-

The favorable accrual adjustments were recorded primarily in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

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

ACQUISITIONS

2005

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

DISPOSITIONS

2006

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

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

2005

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

During 2005, we sold our interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $379 million as of September 30, 2006 and December 31, 2005, which is reflected in Deferred Credits and Other on our Condensed 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 5). The HPL operations did not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008 and the cushion gas arrangement. In addition, we continue holding forward gas contracts, with expirations through 2011, 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 nine months ended September 30, 2006, the change in the mark-to-market value of these positions was less than $100,000.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement and was amended through a series of agreements that AEP and Centrica entered in March 2005. Also in March 2005, we received payments related to the ESM of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in 2005. In March 2006, we received a payment of $70 million related to the ESM for 2005. The ESM payment for 2006 is contingent on Centrica's future operating results and is contractually capped at $20 million. The payments are reflected in Gain/Loss on Disposition of Assets, Net on our Condensed Consolidated Statements of Operations.

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been classified as shown in the following table (in millions):

Three Months ended September 30, 2006 and 2005:

	SEEBOARD (a)	U.K. Generation (b)	Total
2006 Revenue	$ -	$ -	$ -
2006 Pretax Income	-	-	-
2006 Earnings, Net of Tax	-	-	-
2005 Revenue	$ 13	$ -	$ 13
2005 Pretax Income	13	-	13
2005 Earnings, Net of Tax	20	2	22

Nine Months ended September 30, 2006 and 2005:

	SEEBOARD (a)	U.K. Generation(c)	Total
2006 Revenue	$ -	$ -	$ -
2006 Pretax Income	-	9	9
2006 Earnings, Net of Tax	-	6	6
2005 Revenue (Expense)	$ 13	$ (8)	$ 5
2005 Pretax Income (Loss)	13	(8)	5
2005 Earnings (Loss), Net of Tax	29	(3)	26

(a) The amounts relate to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.

(b) The amount relates to a tax adjustment 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. Amounts in 2005 relate to purchase price true-up adjustments and tax adjustments from the sale.

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the nine months ended September 30, 2006 and 2005.

ASSETS HELD FOR SALE AND ASSET IMPAIRMENTS

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, and its petition was denied. Golden Spread then appealed to the Supreme Court of Texas and in August 2006, the court requested a response from the Oklahoma Municipal Power Authority, the Public Utilities Board of the City of Brownsville and us. Responses were due October 27, 2006. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on the terms of the future results of operations. TCC's assets related to the Oklaunion Power Station are classified as Assets Held for Sale on our Condensed Consolidated Balance Sheets at September 30, 2006 and December 31, 2005. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries.

Power Generation Facility (Investments - Other segment)

In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for $64 million. We expect the sale to close in the fourth quarter of 2006. 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 Condensed Consolidated Statements of Operations. We classified the Facility's assets as Assets Held for Sale on our Condensed Consolidated Balance Sheet at September 30, 2006. The Facility does not meet the criteria for discontinued operations reporting.

In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years. Dow will reduce an existing below-current-market long-term power supply contract with us in Texas by 50 MW, and we retain the right to any judgment paid by TEM for breaching the original PPA, as discussed in Note 5.

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following an extensive review of the commercial viability of CSPCo's Conesville Units 1 and 2, management committed to a plan to retire these units 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 the third quarter of 2005 related to our decision to retire the units. We classified the impairment amount in Asset Impairments and Other Related Charges on our Condensed Consolidated Statements of Operations.

Assets Held for Sale at September 30, 2006 and December 31, 2005 are as follows:

September 30, 2006		Texas Plants		Power Generation Facility		Total
Assets:				(in millions)		
Other Current Assets	$	2	$	-	$	2
Property, Plant and Equipment, Net		44		64		108
Total Assets Held for Sale	$	46	$	64	$	110

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

9. **<u>BENEFIT PLANS</u>**

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the following plans for the three and nine months ended September 30, 2006 and 2005:

	Pension Plans				Other Postretirement Benefit Plans			
Three Months Ended September 30, 2006 and 2005:		**2006**		**2005**		**2006**		**2005**
				(in millions)				
Service Cost	$	23	$	23	$	10	$	10
Interest Cost		57		57		26		26
Expected Return on Plan Assets		(82)		(77)		(24)		(23)
Amortization of Transition (Asset) Obligation		-		(1)		7		6
Amortization of Net Actuarial Loss		20		13		5		5
Net Periodic Benefit Cost	$	18	$	15	$	24	$	24

Pension Plans	Other Postretirement

Nine Months Ended September 30, 2006 and 2005:	2006	2005	Benefit Plans 2006	2005
		(in millions)		
Service Cost	$ 71	$ 69	$ 30	$ 31
Interest Cost	171	169	76	79
Expected Return on Plan Assets	(248)	(232)	(70)	(68)
Amortization of Transition (Asset) Obligation	-	(1)	21	20
Amortization of Net Actuarial Loss	59	40	15	19
Net Periodic Benefit Cost	$ 53	$ 45	$ 72	$ 81

10. STOCK-BASED COMPENSATION

As previously approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. A maximum of 9,000,000 shares may be used under this plan for full value share awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original Plan in 2000 and the amended and restated version in 2005. We have not granted options as part of our regular stock-based compensation program since 2003. However, we have used stock 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 the Board of Directors has granted.

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

Stock Options

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

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

The Board of Directors did not award any stock options during the nine months ended September 30, 2006.

The total fair value of stock options vested and the total intrinsic value of options exercised during the nine months ended September 30, 2006 was $3.7 million and $2.3 million, respectively. Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the nine months ended September 30, 2006 is as follows:

	Options		Weighted Average Exercise Price
	(in thousands)		
Outstanding at January 1, 2006	6,222	$	34.16
Granted	-		-
Exercised/Converted	(369)		30.17
Expired	-		-
Forfeited	(209)		41.62
Outstanding at September 30, 2006	5,644		34.15
Exercisable at September 30, 2006	5,384	$	34.41

The following table summarizes information about AEP stock options outstanding at September 30, 2006.

Options Outstanding

2006 Range of Exercise Prices	Number Exercisable (in thousands)	Weighted Average Remaining Life (in years)		Weighted Average Exercise Price		Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	1,359	5.9	$	27.38	$	12,220
$30.76 - $38.65	3,917	3.2		35.44		3,665
$43.79 - $49.00	368	4.6		45.43		-
	5,644	4.0		34.15	$	15,885

The following table summarizes information about AEP stock options exercisable at September 30, 2006.

Options Exercisable

2006 Range of Exercise Prices	Number Exercisable (in thousands)	Weighted Average Remaining Life (in years)		Weighted Average Exercise Price		Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	1,158	5.7	$	27.29	$	10,519
$30.76 - $35.63	3,858	3.2		35.49		3,386
$43.79 - $49.00	368	4.6		45.43		-
	5,384	3.8		34.41	$	13,905

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

Performance Units

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

Our Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the nine months ended September 30, 2006 as follows:

Performance Units		
Awarded Units (in thousands)		864
Unit Fair Value at Grant Date	$	37.36
Vesting Period (years)		3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)		
Awarded Units (in thousands)		91
Weighted Average Grant Date Fair Value	$	35.37
Vesting Period (years) (a)		3

(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.

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

The cash payouts for the nine months ended September 30, 2006 were $2.6 million for performance units and $1.0 million for AEP Career Share distributions.

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

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

Restricted Shares and Restricted Stock Units

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

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

Our Board of Directors awarded 47,050 restricted stock units, including units awarded for dividends, with a weighted average grant date fair value of $35.58 per unit, for the nine months ended September 30, 2006.

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the nine months ended September 30, 2006 was $3.9 million and $4.6 million, respectively.

A summary of the status of our nonvested restricted shares and restricted stock units as of September 30, 2006, and changes during the nine months ended September 30, 2006 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	**Shares/Units (in thousands)**	**Weighted Average Grant Date Fair Value**
Nonvested at January 1, 2006	497	$ 32.19
Granted	47	35.58
Vested	(127)	30.56
Forfeited	(22)	35.52
Nonvested at September 30, 2006	395	32.93

The total aggregate intrinsic value of nonvested restricted shares and restricted stock units as of September 30, 2006 was $14.4 million and the weighted average remaining contractual life was 3.03 years.

Share-based Compensation Plans

Compensation cost, 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 nine months ended September 30, 2006 were as follows:

Share-based Compensation Plans	(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$	16,671
Actual Tax Benefit Realized		5,835
Total Compensation Cost Capitalized		3,746

(a) Compensation cost for share-based payment arrangements is included in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

During the nine months ended September 30, 2006, there were no significant modifications affecting any of our share-based payment arrangements.

As of September 30, 2006, there was $49.1 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the Plan. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the liability is revalued each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.57 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the nine months ended September 30, 2006 was $11.1 million and $0.8 million, respectively.

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

11. INCOME TAXES

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, 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 the Condensed Consolidated Balance Sheet of $48 million of which $2 million was credited to Income Tax Expense and $46 million credited to Regulatory Assets based upon the related rate-making treatment.

12. BUSINESS SEGMENTS

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

Our segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.

- Electricity transmission and distribution in the U.S.

Investments - Gas Operations

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

Investments - UK Operations

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

Investments - Other

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

The tables below present segment income statement information for the three and nine months ended September 30, 2006 and 2005 and balance sheet information as of September 30, 2006 and December 31, 2005. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended September 30, 2006							
Revenues from:							
External Customers	$ 3,485	$ (47)	$ -	$ 156	$ -	$ -	$ 3,594
Other Operating Segments	(44)	51	-	4	1	(12)	-
Total Revenues	$ 3,441	$ 4	$ -	$ 160	$ 1	$ (12)	$ 3,594
Net Income (Loss)	$ 379	$ (3)	$ -	$ (109)	$ (2)	$ -	$ 265

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Three Months Ended September 30, 2005							
Revenues from:							
External Customers	$ 3,152	$ 73	$ -	$ 103	$ -	$ -	$ 3,328
Other Operating Segments	85	(77)	-	3	1	(12)	-

Total Revenues	$ 3,237	$ (4)	$ -	$ 106	$ 1	$ (12)	$ 3,328
Income (Loss) Before Discontinued Operations	$ 352	$ (10)	$ -	$ 28	$ (5)	$ -	$ 365
Discontinued Operations, Net of Tax	-	-	2	20	-	-	22
Net Income (Loss)	$ 352	$ (10)	$ 2	$ 48	$ (5)	$ -	$ 387

	Utility Operations	Gas Operations	Investments UK Operations	Other (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Nine Months Ended September 30, 2006							
Revenues from:							
External Customers	$ 9,282	$ (80)	$ -	$ 436	$ -	$ -	$ 9,638
Other Operating Segments	(73)	89	-	9	2	(27)	-
Total Revenues	$ 9,209	$ 9	$ -	$ 445	$ 2	$ (27)	$ 9,638
Income (Loss) Before Discontinued Operations	$ 904	$ (2)	$ -	$ (80)	$ (7)	$ -	$ 815
Discontinued Operations, Net of Tax	-	-	6	-	-	-	6
Net Income (Loss)	$ 904	$ (2)	$ 6	$ (80)	$ (7)	$ -	$ 821

	Utility Operations	Gas Operations	Investments UK Operations	Other (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Nine Months Ended September 30, 2005							
Revenues from:							
External Customers	$ 8,437	$ 449	$ -	$ 326	$ -	$ -	$ 9,212
Other Operating Segments	186	(167)	-	12	2	(33)	-
Total Revenues	$ 8,623	$ 282	$ -	$ 338	$ 2	$ (33)	$ 9,212
Income (Loss) Before Discontinued Operations	$ 952	$ (2)	$ -	$ 32	$ (45)	$ -	$ 937
Discontinued Operations, Net of Tax	-	-	(3)	29	-	-	26
Net Income (Loss)	$ 952	$ (2)	$ (3)	$ 61	$ (45)	$ -	$ 963

Utility Operations	Gas Operations	Investments UK Operations	Other	All Other (b)	Reconciling Adjustments	Consolidated

					(b)		
				(in millions)			
As of September 30, 2006							
Total Property, Plant and Equipment	$ 40,397	$ 1	$ -	$ 567	$ 3	$ -	$ 40,968
Accumulated Depreciation and Amortization	15,014	-	-	130	2	-	15,146
Total Property, Plant and Equipment - Net	$ 25,383	$ 1	$ -	$ 437	$ 1	$ -	$ 25,822
Total Assets	$ 35,185	$ 591(c)	$ 639(d)	$ 72	$ 10,372	$ (10,474)	$ 36,385
Assets Held for Sale	46	-	-	64	-	-	110

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (b)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
As of December 31, 2005							
Total Property, Plant and Equipment	$ 38,283	$ 2	$ -	$ 833	$ 3	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	1	-	112	1	-	14,837
Total Property, Plant and Equipment - Net	$ 23,560	$ 1	$ -	$ 721	$ 2	$ -	$ 24,284
Total Assets	$ 34,339	$ 1,199(e)	$ 632(f)	$ 509	$ 9,463	$ (9,970)	$ 36,172
Assets Held for Sale	44	-	-	-	-	-	44

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

(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments (included in All Other) in subsidiary companies.

(c) Total Assets of $591 million for the Investments-Gas Operations segment include $321 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $270 million in assets represents third party risk management contracts, margin deposits and accounts receivable.

(d) Total Assets of $639 million for the Investments-UK Operations segment include $625 million in affiliated accounts receivable related mainly to federal income taxes that are eliminated in consolidation. The majority of the remaining $14 million in assets represents cash equivalents.

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

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

13. FINANCING ACTIVITIES

Long-term Debt

Our outstanding long-term debt is as follows:

Type of Debt	September 30, 2006		December 31, 2005	
	(in millions)			
Pollution Control Bonds	$	2,051	$	1,935
Senior Unsecured Notes		8,827		8,226
First Mortgage Bonds		96		196
Defeased First Mortgage Bonds (a)		26		26
Notes Payable		872		904
Securitization Bonds		596		648
Notes Payable To Trust		113		113
Other Long-Term Debt (b)		247		236
Unamortized Discount (net)		(65)		(58)
Total Long-term Debt Outstanding		12,763		12,226
Less Portion Due Within One Year		1,789		1,153
Long-term Portion	$	10,974	$	11,073

(a) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of $18 million at both September 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of $2 million are included in Other Temporary Cash Investments at both September 30, 2006 and December 31, 2005 and $21 million is included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at both September 30, 2006 and December 31, 2005. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond had a balance of $8 million at both September 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of $9 million and $1 million at September 30, 2006 and December 31, 2005, respectively, are included in Other Temporary Cash Investments and $0 and $8 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at September 30, 2006 and December 31, 2005, respectively. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets of

$270 million and $264 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at September 30, 2006 and December 31, 2005, respectively.

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

Company	Type of Debt		Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:					
APCo	Pollution Control Bonds	$	50	Variable	2036
APCo	Senior Unsecured Notes		250	5.55	2011
APCo	Senior Unsecured Notes		250	6.375	2036
I&M	Pollution Control Bonds		50	Variable	2025
OPCo	Pollution Control Bonds		65	Variable	2036
OPCo	Senior Unsecured Notes		350	6.00	2016
PSO	Senior Unsecured Notes		150	6.15	2016
SWEPCo	Pollution Control Bonds		82	Variable	2018
Total Issuances		$	1,247(a)		

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

(a) Amount indicated on statement of cash flows of $1,229 million is net of issuance costs and unamortized premium or discount.

Company	Type of Debt		Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
AEP	Senior Unsecured Notes	$	396	6.125	2006
APCo	First Mortgage Bonds		100	6.80	2006
I&M	Pollution Control Bonds		50	6.55	2025
OPCo	Notes Payable		4	6.81	2008
OPCo	Notes Payable		7	6.27	2009
SWEPCo	Notes Payable		5	4.47	2011
SWEPCo	Notes Payable		2	Variable	2008
SWEPCo	Pollution Control Bonds		82	6.10	2018
TCC	Securitization Bonds		52	5.01	2010
Non-Registrant:					
AEP subsidiaries	Notes Payable		9	Variable	2017
CSW Energy, Inc.	Notes Payable		4	5.88	2011
Total Retirements and Principal Payments		$	711		

In October 2006, TCC issued $1.74 billion in securitization bonds as follows:

Principal Amount (in millions)	Interest Rate (%)	Scheduled Final Payment Date
$ 217	4.98	2010
341	4.98	2013
250	5.09	2015
437	5.17	2018
495	5.3063	2020

The proceeds will be used to retire TCC debt and equity, which are no longer needed to support stranded costs.

In October 2006, I&M had a required remarketing of $65 million of 2.625% pollution control bonds, which were converted from a three-year fixed rate mode to an auction rate mode.

In November 2006, APCo had a required remarketing of $30 million of 2.80% pollution control bonds, which were converted from a three-year fixed rate mode to an auction rate mode.

In November 2006, APCo issued $17.5 million of variable rate pollution control bonds and retired $17.5 million, 2.70% pollution control bonds due in 2007.

In November 2006, $100.6 million of pollution control bonds were put back to TCC on the put date of November 1, 2006. TCC intends to hold these bonds for reissuance at a later date.

Credit Facilities

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

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

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

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

Results of Operations

Net Income was unchanged for the third quarter of 2006 compared with the third quarter of 2005. Net Income increased $0.6 million for the nine months ended September 30, 2006 compared with the nine months ended September 30, 2005. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant which is calculated and adjusted monthly.

Third Quarter of 2006 Compared to Third Quarter of 2005

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

Third Quarter of 2005		$ 2.2
Change in Gross Margin:		
Wholesale Sales		0.2
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(0.7)	
Taxes Other Than Income Taxes	0.7	
Interest Expense	(0.1)	
Total Change in Operating Expenses and Other		(0.1)
Income Tax Expense		(0.1)
Third Quarter of 2006		$ 2.2

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $0.2 million primarily due to recovery of higher expenses.

Other Operation and Maintenance expenses increased primarily due to increased costs at the Rockport Plant for steam plant operation and maintenance of structures.

Taxes Other Than Income Taxes decreased primarily due to lower real and personal property taxes as the prior year accrual was adjusted to the actual amount paid.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Reconciliation of Nine Months Ended September 30, 2005 to Nine Months Ended September 30, 2006 Net Income (in millions)

Nine Months Ended September 30, 2005		$ 6.8
Changes in Gross Margin:		
Wholesale Sales		3.2
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(2.0)	
Taxes Other Than Income Taxes	0.7	
Interest Expense	(0.3)	
Total Change in Operating Expenses and Other		(1.6)
Income Tax Expense		(1.0)
Nine Months Ended September 30, 2006		$ 7.4

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $3.2 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

Other Operation and Maintenance expenses increased $2.0 million primarily due to increased maintenance cost at the Rockport Plant during a planned outage in 2006 and credits allocated to us in February 2005 from the cancellation and settlement of corporate owned life insurance policies.

Taxes Other Than Income Taxes decreased $0.7 million primarily due to lower real and personal property taxes as the prior year accrual was adjusted to the actual amount paid.

Income Taxes

Income Tax Expense increased $1.0 million primarily due to an increase in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Off-Balance Sheet Arrangements

In prior years, we entered into an off-balance sheet arrangement for the lease of Rockport Plant Unit 2. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only traditional operating lease arrangements. Our off-balance sheet arrangement has not changed significantly since year-end. For complete information on our off-balance sheet arrangement see “Off-balance Sheet Arrangements” in the “Management’s Narrative Financial Discussion and Analysis” section of our 2005 Annual Report.

Summary Obligation Information

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

Significant Factors

In July 2006, we remarketed $45 million of pollution control bonds at a rate of 4.15% compared to a previous rate of 4.05% until July 14, 2011, the next remarketing date.

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

Critical Accounting Estimates

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

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2006 and 2005
(Unaudited)
(in thousands)

	Three Months Ended 2006	Three Months Ended 2005	Nine Months Ended 2006	Nine Months Ended 2005
OPERATING REVENUES	$ 74,756	$ 69,640	$ 230,102	$ 201,268
EXPENSES				
Fuel for Electric Generation	42,354	37,403	131,402	105,771
Rent - Rockport Plant Unit 2	17,070	17,070	51,212	51,212
Other Operation	3,381	2,803	9,598	8,376
Maintenance	2,522	2,421	7,238	6,411
Depreciation and Amortization	5,951	5,956	17,858	17,901
Taxes Other Than Income Taxes	368	1,074	2,466	3,149
TOTAL	71,646	66,727	219,774	192,820
OPERATING INCOME	3,110	2,913	10,328	8,448
Other Income (Expense):				
Interest Income	-	-	-	24
Allowance for Equity Funds Used During Construction	-	-	24	60
Interest Expense	(774)	(652)	(2,137)	(1,848)
INCOME BEFORE INCOME TAXES	2,336	2,261	8,215	6,684
Income Tax Expense (Credit)	117	22	848	(144)
NET INCOME	$ 2,219	$ 2,239	$ 7,367	$ 6,828

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three and Nine Months Ended September 30, 2006 and 2005
(Unaudited)
(in thousands)

	Three Months Ended 2006	Three Months Ended 2005	Nine Months Ended 2006	Nine Months Ended 2005
BALANCE AT BEGINNING OF PERIOD	$ 27,176	$ 26,947	$ 26,038	$ 24,237
Net Income	2,219	2,239	7,367	6,828
Cash Dividends Declared	-	3,015	4,010	4,894
BALANCE AT END OF PERIOD	$ 29,395	$ 26,171	$ 29,395	$ 26,171

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2006 and December 31, 2005
(Unaudited)
(in thousands)

		2006		2005
CURRENT ASSETS				
Accounts Receivable - Affiliated Companies	$	24,356	$	29,671
Fuel		24,139		14,897
Materials and Supplies		7,913		7,017
Accrued Tax Benefits		2,009		2,074
Prepayments and Other		105		9
TOTAL		58,522		53,668
PROPERTY, PLANT AND EQUIPMENT				
Electric - Production		686,025		684,721
Other		2,385		2,369
Construction Work in Progress		11,391		12,252
Total		699,801		699,342
Accumulated Depreciation and Amortization		393,529		382,925
TOTAL - NET		306,272		316,417
Noncurrent Assets		7,738		6,618
TOTAL ASSETS	$	372,532	$	376,703

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 14,938	$ 35,131
Accounts Payable:		
General	1,311	926
Affiliated Companies	21,018	22,161
Long-term Debt Due Within One Year	-	44,828
Accrued Taxes	5,880	3,055
Accrued Rent - Rockport Plant Unit 2	23,427	4,963
Other	805	1,228
TOTAL	67,379	112,292
NONCURRENT LIABILITIES		
Long-term Debt	44,835	-
Deferred Income Taxes	20,852	23,617
Asset Retirement Obligations	1,399	1,370
Regulatory Liabilities and Deferred Investment Tax Credits	82,331	82,689
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	90,155	94,333
Obligations Under Capital Leases	11,752	11,930
TOTAL	251,324	213,939
TOTAL LIABILITIES	318,703	326,231
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $1,000 Par Value Per Share		
Authorized and Outstanding - 1,000 Shares	1,000	1,000
Paid-in Capital	23,434	23,434
Retained Earnings	29,395	26,038
TOTAL	53,829	50,472
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 372,532	$ 376,703

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 7,367	$ 6,828
Adjustments for Noncash Items:		
Depreciation and Amortization	17,858	17,901
Deferred Income Taxes	(3,468)	(3,539)
Deferred Investment Tax Credits	(2,482)	(2,501)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(4,178)	(4,178)
Deferred Property Taxes	(893)	(1,010)
Changes in Other Noncurrent Assets	(2,885)	(1,736)
Changes in Other Noncurrent Liabilities	2,776	2,201
Changes in Components of Working Capital:		
Accounts Receivable	5,315	(2,469)
Fuel, Materials and Supplies	(10,138)	4,278
Accounts Payable	(758)	(1,188)
Accrued Taxes, Net	2,890	(2,982)
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(96)	(17)
Other Current Liabilities	(423)	(363)
Net Cash Flows From Operating Activities	29,349	29,689
INVESTING ACTIVITIES		
Construction Expenditures	(4,978)	(9,041)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(20,193)	(15,601)
Principal Payments for Capital Lease Obligations	(168)	(153)
Dividends Paid	(4,010)	(4,894)
Net Cash Flows Used For Financing Activities	(24,371)	(20,648)
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	$ 2,413	$ 2,104
Net Cash Paid for Income Taxes	6,037	11,025
Noncash Acquisitions Under Capital Leases	78	31

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

The condensed notes to AEGCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to AEGCo.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Our sharing of margins ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us. As of September 30, 2006, we have no dedicated contracts.

Results of Operations

Third Quarter of 2006 Compared to Third Quarter of 2005

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

Third Quarter of 2005		$ 40
Changes in Gross Margin:		
Texas Supply	(4)	
Texas Wires	(1)	
Off-system Sales	(18)	
Transmission Revenues	(3)	
Other	(3)	
Total Change in Gross Margin		(29)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	1	
Carrying Costs Income	10	
Other Income	(7)	
Interest Expense	(11)	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		13
Third Quarter of 2006		$ 17

Net Income decreased $23 million to $17 million in 2006. The key drivers of the decrease were a $29 million decrease in Gross Margin and a $7 million increase in Operating Expenses and Other, partially offset by a reduction in Income Tax Expense of $13 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 cost of fuel, consumption of chemicals and emissions allowances, and purchased power, were as follows:

- Texas Supply margins decreased $4 million primarily due to lower nonaffiliated sales of $3 million.
- Margins from Off-system Sales decreased $18 million due to an $11 million decrease in margin sharing under the SIA (no current margin sharing under the CSW Operating Agreement and the SIA) and a $7 million decrease in margins from optimization activities. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- Transmission Revenues decreased $3 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 decreased $3 million primarily due to lower securitization revenues of $3 million. Securitization revenues 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.

Operating Expenses and Other changed between years as follows:

- Carrying Costs Income increased $10 million primarily due to a negative adjustment of $8 million made in the third quarter of 2005 related to our True-up Proceeding orders received from the PUCT.
- 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 "Texas Restructuring - Excess Earnings" section of Note 4).
- Interest Expense increased $11 million primarily due to a $9 million increase in accrued interest related to the Texas competition transition charge liability (See "Texas Restructuring - CTC Proceeding for Other True-up Items" section of Note 4).

Income Taxes

The decrease in Income Tax Expense of $13 million is primarily due to a decrease in pretax book income.

<u>Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005</u>

Reconciliation of Nine Months Ended September 30, 2005 to
Nine Months Ended September 30, 2006 Net Income
(in millions)

Nine Months Ended September 30, 2005		$ 70
Changes in Gross Margin:		
Texas Supply	(78)	
Texas Wires	14	
Off-system Sales	(21)	
Transmission Revenues	(12)	
Other	(9)	
Total Change in Gross Margin		(106)
Changes in Operating Expenses and Other:		

Other Operation and Maintenance	50		
Depreciation and Amortization	(6)		
Taxes Other Than Income Taxes	6		
Carrying Costs Income	35		
Other Income	(13)		
Interest Expense	(8)		
Total Change in Operating Expenses and Other			64
Income Tax Expense			10
Nine Months Ended September 30, 2006		$	38

Net Income decreased $32 million to $38 million in 2006. The key driver of the decrease was a $106 million decrease in Gross Margin, partially offset by a reduction in Other Operation and Maintenance expenses of $50 million and increased Carrying Costs Income of $35 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 cost of fuel, consumption of chemicals and emissions allowances, and purchased power, were as follows:

- Texas Supply margins decreased $78 million primarily due to the sale of STP, which resulted in lower nonaffiliated sales of $101 million and a $6 million provision for refund primarily due to the fuel reconciliation adjustment in 2005. These decreases were partially offset by lower fuel and purchased power expenses of $30 million.
- Texas Wires revenues increased $14 million primarily due to favorable prices and a five percent increase in degree days.
- Margins from Off-system Sales decreased $21 million due to a $15 million decrease in margin sharing under the SIA and a $6 million decrease in margins from optimization activities. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- 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 decreased $9 million primarily due to lower third party construction project revenues of $4 million related to work performed for the Lower Colorado River Authority and reduced securitization revenues of $6 million. Securitization revenues 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.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $50 million primarily due to a $12 million decrease in plant operations, a $14 million decrease in plant maintenance, a $6 million decrease in administrative and general expenses and the absence of $7 million in accretion expense all related to the sale of STP. An additional $4 million decrease resulted from lower expenses related to construction activities performed for third parties, primarily the Lower Colorado River Authority.
- Depreciation and Amortization expense increased $6 million primarily related to the refund and amortization of excess earnings credits in 2005 partially offset by the recovery and amortization of securitized assets.
-

Taxes Other Than Income Taxes decreased $6 million primarily due to lower property-related taxes as a result of the sale of STP in 2005 and the favorable settlement of a state use tax audit in 2006.

· Carrying Costs Income increased $35 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.
· Other Income decreased $13 million primarily due to interest income recorded in the prior year related to the 2005 Texas Court of Appeals order (See “Texas Restructuring - Excess Earnings” section of Note 4).
· Interest Expense increased $8 million primarily due to a $12 million increase in accrued interest related to the Texas CTC liability (see “Texas Restructuring - CTC Proceeding for Other True-up Items” section of Note 4) partially offset by a $2 million decrease in interest expense associated with securitization revenues.

Income Taxes

The decrease in Income Tax Expense of $10 million is primarily due to a decrease in pretax book income, offset in part by tax reserve adjustments, a decrease in the amortization of investment tax credits due to the sale in May 2005 of STP and a decrease in consolidated tax savings from AEP.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the nine months ended September 30, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ -	$ 26
Net Cash Flows From (Used For):		
Operating Activities	137,471	(95,431)
Investing Activities	(197,269)	293,461
Financing Activities	59,803	(198,053)
Net Increase (Decrease) in Cash and Cash Equivalents	5	(23)
Cash and Cash Equivalents at End of Period	$ 5	$ 3

Operating Activities

Net Cash Flows From Operating Activities were $137 million during the first nine months of 2006. We produced Net Income of $38 million during the period and incurred noncash items of $111 million for Depreciation and Amortization and $(65) million for Carrying Costs on Stranded Cost Recovery. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items; the most significant are decreases in Accounts Receivable, Net partially offset by a decrease in Accounts Payable. Accounts Receivable, Net decreased $159 million primarily due to cash received for the retail clawback of $61 million and 2005 storm restoration performed for nonaffiliated companies of $12 million. In addition, our removal from the SIA and CSW Operating Agreement effective May 1, 2006 resulted in fewer energy-related receivables. Accounts Payable decreased $108 million primarily due to lower energy-related transactions resulting from our removal from the SIA and CSW Operating Agreement.

Net Cash Flows Used For Operating Activities were $95 million during the first nine months of 2005. We produced income of $70 million during the period including noncash expense items of $105 million for Depreciation and Amortization and $(63) 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 activity in these asset and liability accounts relate to a number of items; the most significant is a decrease in Accrued Taxes, Net. Accrued Taxes, Net decreased $111 million primarily as a result of taxes remitted to the government related to prior year and current year tax accruals.

Investing Activities

Net Cash Flows Used For Investing Activities in 2006 were $197 million primarily due to $203 million of Construction Expenditures focused mainly on improved service reliability projects for transmission and distribution systems. For the remainder of 2006, we expect $83 million in Construction Expenditures.

Net Cash Flows From Investing Activities in 2005 were $293 million primarily due to $314 million of net proceeds from the sale of the STP nuclear plant and a reduction in Other Cash Deposits, Net of $93 million primarily for the retirement of defeased first mortgage bonds of $66 million. These cash inflows were partially offset by cash used for construction expenditures of $109 million related to projects for transmission and distribution service reliability.

Financing Activities

Net Cash Flows From Financing Activities in 2006 were $60 million primarily due to the issuance of $195 million of affiliated notes with AEP. This increase in long-term debt was partially offset by a decrease in Advances from Affiliates, Net of $82 million and the retirement of $52 million of securitization bonds.

Net Cash Flows Used for Financing Activities in 2005 were $198 million primarily due to the payments of dividends of $150 million and the retirement of long-term debt of $486 million, including $66 million of bonds that were defeased in 2004. This was partially offset by an issuance of new debt of $427 million, including $150 million of affiliated long-term debt.

Financing Activity

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

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date

		(in thousands)	(%)	
Notes Payable - Affiliated	$	125,000	5.14	2007
Notes Payable - Affiliated		70,000	5.86	2007

Retirements

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Securitization Bonds	$	52,265	5.01	2010

In October 2006 TCC issued $1.74 billion in securitization bonds, as follows:

	Principal Amount (in thousands)	Interest Rate (%)	Scheduled Final Payment Date
$	217,000	4.98	2010
	341,000	4.98	2013
	250,000	5.09	2015
	437,000	5.17	2018
	494,700	5.3063	2020

The proceeds will generally be used to retire TCC debt and equity, which are no longer needed to support stranded costs.

In October 2006, we retired $345 million in intercompany notes payable as follows:

	Principal Amount (in thousands)	Interest Rate (%)	Due Date
$	150,000	4.58	2007
	125,000	5.14	2007
	70,000	5.86	2007

In November 2006, $100.6 million of pollution control bonds were put back to TCC on the put date of November 1, 2006. TCC intends to hold these bonds for reissuance at a later date.

In October 2006, we also paid a special dividend of $585 million to AEP.

Liquidity

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

We will use proceeds received from the securitization to pay down a portion of our equity and debt and to pay any necessary accelerated refunds related to the CTC (discussed below under Texas Restructuring).

Summary Obligation Information

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

Significant Factors

Texas Restructuring

In June 2006, we filed to implement a CTC refund of $357 million for our other true-up items over eight years. The differences between the components of our Recorded Net Regulatory Liabilities - Other True-up Items as of September 30, 2006 (including interest) and our Net CTC Refund Proposed are detailed below**:**

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		31
Retail Clawback including Carrying Costs		(65)
Deferred Over-recovered Fuel Balance		(184)
Retrospective ADFIT Benefit		(77)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(238)
Unrecorded Prospective ADFIT Benefit		(240)
Gross CTC Refund Proposed		(478)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		98
Net CTC Refund Proposed, After Deferrals		(364)
True-up Proceeding Expense Surcharge		7
Net CTC Refund Proposed, After Deferrals and Expenses	$	(357)

In September 2006, the PUCT approved an interim CTC that was implemented on October 12, 2006, the same day that we began billing customers for the securitization bonds. The interim CTC will refund the entire retail clawback of $65 million (including carrying costs) to residential customers by the end of 2006. The CTC refund to the other customer classes during the interim period will be as proposed by us, with the exception of the large industrials, who will not receive any fuel refunds during the interim period.

At an October 2006 open meeting, the PUCT announced oral decisions regarding the CTC refund. A final written order is expected in late November or early December of this year. In its decision, the PUCT confirmed that TCC can use securitization bond proceeds to make the CTC refund. The PUCT's decision was to continue the interim CTC through December 2006 to complete the refund of the retail clawback over three months. Beginning in January 2007, the Deferred Over-recovered Fuel Balance will be refunded over six months with the large industrial customers receiving their entire refund in January 2007. Starting in July 2007, the remaining CTC items will be refunded over one year, except that the PUCT agreed with our request to defer the refund of the ADITC and EDFIT Benefit Refund

Deferral and the FERC Jurisdictional Fuel Refund Deferral (see table above). The PUCT will decide those issues and related amounts in another proceeding.

Municipal customers and other intervenors appealed the PUCT orders seeking to further reduce our true-up recoveries. If we determine, as a result of future PUCT orders or appeal court rulings, that it is probable we cannot recover a portion of our recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. We appealed the PUCT orders seeking relief in both state and federal court where we believe the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- the PUCT ruled that TCC did not comply with the statute and PUCT rules regarding the auction of 15% of its Texas jurisdictional installed capacity,
- 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 gas units with the sale of its coal unit,
- and two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects our deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of $104 million of our ADITC and the loss of future accelerated tax depreciation election. The estimated future impact on earnings of the Texas Restructuring as of September 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves our CTC filing, including the interim refund, is detailed below:

		(in millions)
ADITC and EDFIT Benefits Reducing Securitization	$	98
ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets		(60)
Securitization Settlement		(77)
Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund		(240)
Unrecorded Equity Carrying Costs Recognized as Collected		224
Future Interest Payable on Proposed CTC Refund		(19)
Deferred Fuel - Federal Jurisdictional Issue		16
Net Adverse Earnings Impact Over 14 Years	$	(58)

If the PUCT changes its oral decision regarding the proposed CTC deferral and the two contingent federal matters are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to $181 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the $2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of $797 million and from the $1.74 billion sale of securitization bonds in October 2006 less the proposed $357 million CTC refund over the next eight years.

Litigation and Regulatory Activity

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

Critical Accounting Estimates

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

Our MTM Risk Management Contract Net Assets are zero as of September 30, 2006. For further explanation, see "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

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
Nine Months Ended September 30, 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		(1,175)
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		-
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(3,868)
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 September 30, 2006	$	-

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

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

Our MTM Risk Management Contracts Net Assets are zero as of September 30, 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 Condensed Consolidated Balance Sheet

As a result of changes made to the Allocation Agreement between AEP East companies and AEP West companies in the second quarter of 2006, we are no longer exposed to market fluctuations in energy commodity prices. Therefore, we have no contracts designated as cash flow hedges on our September 30, 2006 Condensed Consolidated Balance Sheet.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to September 30, 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
Nine Months Ended September 30, 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 Income for Cash Flow Hedges Settled	6
Ending Balance in AOCI September 30, 2006	$ -

(a) See "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

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 September 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Nine Months Ended September 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$11	$2	$-	$111	$184	$88	$32

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $70 million and $93 million at September 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Electric Generation, Transmission and Distribution	$ 162,902	$ 192,932	$ 435,801	$ 559,822
Sales to AEP Affiliates	1,559	2,528	4,703	12,794
Other - Nonaffiliated	9,462	7,905	30,196	34,432
TOTAL	173,923	203,365	470,700	607,048
EXPENSES				
Fuel and Other Consumables for Electric Generation	2,006	1,915	4,728	12,047
Purchased Electricity for Resale	725	1,691	3,557	27,057
Other Operation	61,057	64,408	183,241	221,741
Maintenance	10,679	8,782	27,255	38,254
Depreciation and Amortization	40,298	40,342	110,848	105,062
Taxes Other Than Income Taxes	23,387	22,828	60,421	66,282
TOTAL	138,152	139,966	390,050	470,443
OPERATING INCOME	35,771	63,399	80,650	136,605
Other Income (Expense):				
Interest Income	560	8,295	1,592	15,722
Carrying Costs Income	25,443	15,349	65,279	30,146
Allowance for Equity Funds Used During Construction	667	(59)	1,671	641
Interest Expense	(36,746)	(25,374)	(93,401)	(85,095)
INCOME BEFORE INCOME TAXES	25,695	61,610	55,791	98,019
Income Tax Expense	8,460	21,134	17,808	28,038
NET INCOME	17,235	40,476	37,983	69,981
Preferred Stock Dividend Requirements	60	60	181	181
EARNINGS APPLICABLE TO COMMON STOCK	$ 17,175	$ 40,416	$ 37,802	$ 69,800

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(181)		(181)
TOTAL					1,118,462
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,626				(3,021)	(3,021)
Minimum Pension Liability, Net of Tax of $0				3,810	3,810
NET INCOME			69,981		69,981
TOTAL COMPREHENSIVE INCOME					70,770
SEPTEMBER 30, 2005	$ 55,292	$ 132,606	$ 1,004,704	$ (3,370)	$ 1,189,232
DECEMBER 31, 2005	$ 55,292	$ 132,606	$ 760,884	$ (1,152)	$ 947,630
Preferred Stock Dividends			(181)		(181)
TOTAL					947,449
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $121				224	224
NET INCOME			37,983		37,983
TOTAL COMPREHENSIVE INCOME					38,207
SEPTEMBER 30, 2006	$ 55,292	$ 132,606	$ 798,686	$ (928)	$ 985,656

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

		2006		2005
CURRENT ASSETS				
Cash and Cash Equivalents	$	5	$	-
Other Cash Deposits		41,728		66,153
Advances to Affiliates		25,304		-
Accounts Receivable:				
Customers		65,875		209,957
Affiliated Companies		8,633		23,486
Accrued Unbilled Revenues		25,350		25,606
Allowance for Uncollectible Accounts		(217)		(143)
Total Accounts Receivable		99,641		258,906
Unbilled Construction Costs		6,352		19,440
Materials and Supplies		24,995		13,897
Risk Management Assets		-		14,311
Prepayments and Other		5,645		5,231
TOTAL		203,670		377,938
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Transmission		900,774		817,351
Distribution		1,559,593		1,476,683
Other		232,023		233,361
Construction Work in Progress		126,418		129,800
Total		2,818,808		2,657,195
Accumulated Depreciation and Amortization		637,517		636,078
TOTAL - NET		2,181,291		2,021,117
OTHER NONCURRENT ASSETS				
Regulatory Assets		1,710,352		1,688,787
Securitized Transition Assets		557,520		593,401
Long-term Risk Management Assets		-		11,609
Employee Benefits and Pension Assets		112,594		114,733
Deferred Charges and Other		57,276		53,011
TOTAL		2,437,742		2,461,541
Assets Held for Sale - Texas Generation Plants		45,863		44,316
TOTAL ASSETS	$	4,868,566	$	4,904,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 82,080
Accounts Payable:		
General	20,889	82,666
Affiliated Companies	18,160	65,574
Long-term Debt Due Within One Year - Nonaffiliated	153,364	152,900
Long-term Debt Due Within One Year - Affiliated	345,000	-
Risk Management Liabilities	-	13,024
Accrued Taxes	74,887	54,566
Accrued Interest	16,011	32,497
Other	32,500	45,927
TOTAL	660,811	529,234
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	1,498,031	1,550,596
Long-term Debt - Affiliated	-	150,000
Long-term Risk Management Liabilities	-	7,857
Deferred Income Taxes	1,014,840	1,048,372
Regulatory Liabilities and Deferred Investment Tax Credits	684,566	652,143
Deferred Credits and Other	18,723	13,140
TOTAL	3,216,160	3,422,108
TOTAL LIABILITIES	3,876,971	3,951,342
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,939	5,940
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $25 Par Value Per Share:		
Authorized - 12,000,000 Shares		
Outstanding - 2,211,678 Shares	55,292	55,292
Paid-in Capital	132,606	132,606
Retained Earnings	798,686	760,884
Accumulated Other Comprehensive Income (Loss)	(928)	(1,152)
TOTAL	985,656	947,630
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,868,566	$ 4,904,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 37,983	$ 69,981
Adjustments for Noncash Items:		
Depreciation and Amortization	110,848	105,062
Accretion of Asset Retirement Obligations	55	7,549
Deferred Income Taxes	5,770	(63,426)
Carrying Costs on Stranded Cost Recovery	(65,279)	(30,146)
Mark-to-Market of Risk Management Contracts	5,426	(1,139)
Over/Under Fuel Recovery	7,225	(2,000)
Deferred Property Taxes	(8,296)	(7,600)
Change in Other Noncurrent Assets	17,653	(9,777)
Change in Other Noncurrent Liabilities	(17,249)	(1,390)
Changes in Components of Working Capital:		
Accounts Receivable, Net	159,265	(22,504)
Fuel, Materials and Supplies	(11,508)	(1,763)
Accounts Payable	(107,505)	(10,533)
Customer Deposits	(6,461)	12,844
Accrued Taxes, Net	16,387	(110,975)
Accrued Interest	(16,486)	(24,495)
Other Current Assets	16,611	(13,709)
Other Current Liabilities	(6,968)	8,590
Net Cash Flows From (Used For) Operating Activities	137,471	(95,431)
INVESTING ACTIVITIES		
Construction Expenditures	(203,116)	(109,372)
Change in Other Cash Deposits, Net	25,068	93,427
Change in Advances to Affiliates, Net	(25,304)	-
Purchases of Investment Securities	-	(154,364)
Sales of Investment Securities	-	149,804
Proceeds from Sale of Assets	6,083	313,966
Net Cash Flows From (Used For) Investing Activities	(197,269)	293,461
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	276,663
Issuance of Long-term Debt - Affiliated	195,000	150,000
Change in Advances from Affiliates, Net	(82,080)	11,814
Retirement of Long-term Debt	(52,265)	(486,007)
Retirement of Preferred Stock	(1)	-
Principal Payments for Capital Lease Obligations	(670)	(342)
Dividends Paid on Common Stock	-	(150,000)
Dividends Paid on Cumulative Preferred Stock	(181)	(181)
Net Cash Flows From (Used For) Financing Activities	59,803	(198,053)

Net Increase (Decrease) in Cash and Cash Equivalents		5		(23)
Cash and Cash Equivalents at Beginning of Period		-		26
Cash and Cash Equivalents at End of Period	$	5	$	3
SUPPLEMENTAL DISCLOSURE				
Cash Paid for Interest, Net of Capitalized Amounts	$	93,165	$	95,066
Net Cash Paid (Received) for Income Taxes		(2,764)		207,079
Noncash Acquisitions Under Capital Leases		3,282		277
Construction Expenditures Included in Accounts Payable at September 30,		9,351		8,797

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

The condensed notes to TCC's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to TCC.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY

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

Allocation Agreement between AEP East companies and AEP West companies

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

AEP Texas North Generation Company, LLC

In the third quarter of 2006, we created a new wholly-owned subsidiary, AEP Texas North Generation Company, LLC (TNGC). Following the creation of this subsidiary, we transferred all of our mothballed generation assets and related liabilities to this new subsidiary, substantially completing the business separation requirement of the Texas Restructuring Legislation. Subsequently, TNGC became a participant in the Nonutility Money Pool. The creation of TNGC did not have a significant impact on our results of operations or financial condition.

Results of Operations

Third Quarter of 2006 Compared to Third Quarter of 2005

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

Third Quarter of 2005		$ 22
Changes in Gross Margin:		
Texas Supply	(12)	
Texas Wires	(1)	
Off-system Sales	(10)	
Transmission Revenues	1	
Total Change in Gross Margin		(22)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance		1
Income Tax Expense		7
Third Quarter of 2006		$ 8

Net Income decreased $14 million to $8 million in 2006 primarily due to a decrease in Gross Margin of $22 million, partially offset by a reduction 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, consumption of chemicals and emissions allowances, and purchased power, were as follows:

- Texas Supply margins decreased $12 million primarily due to a $28 million decrease in dedicated energy and capacity sales, offset by $16 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by market conditions within ERCOT.
- Margins from Off-system Sales decreased $10 million due to a $5 million decrease in margin sharing under the SIA (no current margin sharing under the CSW Operating Agreement and the SIA) and a $5 million decrease in margins from optimization activities. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

Income Taxes

The decrease in Income Tax Expense of $7 million is primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Reconciliation of Nine Months Ended September 30, 2005 to
Nine Months Ended September 30, 2006 Net Income
(in millions)

Nine Months Ended September 30, 2005		$ 42
Changes in Gross Margin:		
Texas Supply	(29)	
Texas Wires	(2)	
Off-system Sales	(11)	
Transmission Revenues	(5)	
Other	(39)	
Total Change in Gross Margin		(86)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	38	
Interest Expense	1	
Total Change in Operating Expenses and Other		39
Income Tax Expense		17
Nine Months Ended September 30, 2006		$ 12

Net Income decreased $30 million to $12 million in 2006 primarily due to a decrease in Gross Margin of $86 million partially offset by a reduction in Other Operation and Maintenance expenses of $38 million and a reduction in Income Tax Expense of $17 million.

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

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Texas Supply margins decreased $29 million primarily due to a $58 million decrease in dedicated energy and capacity sales, offset by $28 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by market conditions within ERCOT.

- Margins from Off-system Sales decreased $11 million due to a $6 million decrease in margin sharing under the SIA and a $5 million decrease in margins from optimization activities. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- Transmission Revenues decreased $5 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 certain 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 $38 million primarily due to lower expenses related to the completion of certain third party construction projects related to work performed for the Lower Colorado River Authority.

Income Taxes

The decrease in Income Tax Expense of $17 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook, except for Fitch which 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-

Financing Activity

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

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, TNC participates in the Utility Money Pool and TNGC participates in the Nonutility Money Pool, both of which provide access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end except for Energy and Capacity Purchase Contracts. We exited both the SIA and CSW Operating Agreement, eliminating our future obligation for Energy and Capacity Purchase Contracts. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

Significant Factors

Litigation and Regulatory Activity

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

Critical Accounting Estimates

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of September 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ -	$ -	$ -
Noncurrent Assets	-	-	-
Total MTM Derivative Contract Assets	-	-	-
Current Liabilities	(2,138)	-	(2,138)
Noncurrent Liabilities	-	(2,057)	(2,057)
Total MTM Derivative Contract Liabilities	(2,138)	(2,057)	(4,195)
Total MTM Derivative Contract Net Assets (Liabilities)	$ (2,138)	$ (2,057)	$ (4,195)

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 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	(585)
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)	(3,437)
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 (Liabilities)	(2,138)
Net Cash Flow Hedge Contracts	(2,057)
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2006	$ (4,195)

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

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

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted - Exchange Traded Contracts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(2,138)	-	-	-	-	-	(2,138)
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$ (2,138)	$ -	$ -	$ -	$ -	$ -	$ (2,138)

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to September 30, 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
Nine Months Ended September 30, 2006

(in thousands)

		Power
Beginning Balance in AOCI December 31, 2005	$	(111)
Changes in Fair Value		(1,337)
Impact Due to Change in SIA (a)		98
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled		13
Ending Balance in AOCI September 30, 2006	$	(1,337)

(a) See "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

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

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 September 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Nine Months Ended September 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$23	$4	$-	$55	$92	$44	$16

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $11 million and $13 million at September 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Electric Generation, Transmission and Distribution	$ 79,805	$ 111,107	$ 219,681	$ 280,195
Sales to AEP Affiliates	7,711	13,019	25,596	37,189
Other	246	1,971	149	42,324
TOTAL	87,762	126,097	245,426	359,708
EXPENSES				
Fuel and Other Consumables for Electric Generation	14,016	13,433	33,175	37,772
Purchased Electricity for Resale	14,606	34,425	60,343	88,367
Purchased Electricity from AEP Affiliates	2,436	1	3,978	23
Other Operation	19,003	18,878	59,192	97,135
Maintenance	5,088	5,954	15,505	15,093
Depreciation and Amortization	10,767	10,435	31,172	30,952
Taxes Other Than Income Taxes	5,478	6,047	16,874	17,465
TOTAL	71,394	89,173	220,239	286,807
OPERATING INCOME	16,368	36,924	25,187	72,901
Other Income (Expense):				
Interest Income	203	890	542	1,688
Allowance for Equity Funds Used During Construction	146	137	636	366
Interest Expense	(4,472)	(4,931)	(13,351)	(14,784)
INCOME BEFORE INCOME TAXES	12,245	33,020	13,014	60,171
Income Tax Expense	3,799	10,716	1,326	18,469
NET INCOME	8,446	22,304	11,688	41,702
Preferred Stock Dividend Requirements	26	26	78	78
Gain on Reacquired Preferred Stock	-	-	2	-
EARNINGS APPLICABLE TO COMMON STOCK	$ 8,420	$ 22,278	$ 11,612	$ 41,624

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421
Common Stock Dividends			(20,827)		(20,827)
Preferred Stock Dividends			(78)		(78)
TOTAL					289,516
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $698				(1,296)	(1,296)
NET INCOME			41,702		41,702
TOTAL COMPREHENSIVE INCOME					40,406
SEPTEMBER 30, 2005	$ 137,214	$ 2,351	$ 191,781	$ (1,424)	$ 329,922
DECEMBER 31, 2005	$ 137,214	$ 2,351	$ 174,858	$ (504)	$ 313,919
Common Stock Dividends			(12,750)		(12,750)
Preferred Stock Dividends			(78)		(78)
Gain on Reacquired Preferred Stock			2		2
TOTAL					301,093
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $660				(1,226)	(1,226)
NET INCOME			11,688		11,688
TOTAL COMPREHENSIVE INCOME					10,462
SEPTEMBER 30, 2006	$ 137,214	$ 2,351	$ 173,720	$ (1,730)	$ 311,555

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ -
Other Cash Deposits	9,087	1,432
Advances to Affiliates	4,383	34,286
Accounts Receivable:		
Customers	23,367	77,678
Affiliated Companies	11,910	26,149
Accrued Unbilled Revenues	2,567	5,016
Allowance for Uncollectible Accounts	(24)	(18)
Total Accounts Receivable	37,820	108,825
Fuel	5,528	2,636
Materials and Supplies	8,459	6,858
Risk Management Assets	-	7,114
Prepayments and Other	1,537	3,772
TOTAL	66,814	164,923
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	290,391	288,934
Transmission	324,724	289,029
Distribution	507,307	492,878
Other	165,403	167,849
Construction Work in Progress	31,991	46,424
Total	1,319,816	1,285,114
Accumulated Depreciation and Amortization	486,131	478,519
TOTAL - NET	833,685	806,595
OTHER NONCURRENT ASSETS		
Regulatory Assets	8,920	9,787
Long-term Risk Management Assets	-	5,772
Employee Benefits and Pension Assets	45,409	46,289
Deferred Charges and Other	7,153	10,468
TOTAL	61,482	72,316
TOTAL ASSETS	$ 961,981	$ 1,043,834

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Accounts Payable:		
General	$ 9,151	$ 19,739
Affiliated Companies	27,854	84,923
Long-term Debt Due Within One Year - Nonaffiliated	8,151	-
Risk Management Liabilities	2,138	6,475
Accrued Taxes	29,458	21,212
Other	11,203	21,050
TOTAL	87,955	153,399
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	268,762	276,845
Long-term Risk Management Liabilities	2,057	3,906
Deferred Income Taxes	123,991	132,335
Regulatory Liabilities and Deferred Investment Tax Credits	143,506	139,732
Deferred Credits and Other	21,806	21,341
TOTAL	560,122	574,159
TOTAL LIABILITIES	648,077	727,558
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,357
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock - $25 Par Value Per Share:		
Authorized - 7,800,000 Shares		
Outstanding - 5,488,560 Shares	137,214	137,214
Paid-in Capital	2,351	2,351
Retained Earnings	173,720	174,858
Accumulated Other Comprehensive Income (Loss)	(1,730)	(504)
TOTAL	311,555	313,919
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 961,981	$ 1,043,834

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

		2006		2005
OPERATING ACTIVITIES				
Net Income	$	11,688	$	41,702
Adjustments for Noncash Items:				
Depreciation and Amortization		31,172		30,952
Deferred Income Taxes		(4,667)		(313)
Mark-to-Market of Risk Management Contracts		4,836		(452)
Deferred Property Taxes		(4,359)		(4,072)
Change in Other Noncurrent Assets		(5,173)		(1,109)
Change in Other Noncurrent Liabilities		(630)		(71)
Changes in Components of Working Capital:				
Accounts Receivable, Net		71,005		9,366
Fuel, Materials and Supplies		(4,493)		922
Accounts Payable		(66,653)		16,834
Customer Deposits		(3,571)		5,471
Accrued Taxes, Net		7,984		(10,097)
Other Current Assets		2,496		11,189
Other Current Liabilities		(5,304)		(551)
Net Cash Flows From Operating Activities		34,331		99,771
INVESTING ACTIVITIES				
Construction Expenditures		(52,366)		(44,865)
Change in Other Cash Deposits, Net		979		1,508
Change In Advances to Affiliates, Net		29,903		(36,147)
Proceeds from Sale of Assets		250		1,033
Net Cash Flows Used For Investing Activities		(21,234)		(78,471)
FINANCING ACTIVITIES				
Retirement of Preferred Stock		(6)		-
Principal Payments for Capital Lease Obligations		(263)		(180)
Dividends Paid on Common Stock		(12,750)		(20,827)
Dividends Paid on Cumulative Preferred Stock		(78)		(78)
Net Cash Flows Used For Financing Activities		(13,097)		(21,085)
Net Increase in Cash and Cash Equivalents		-		215
Cash and Cash Equivalents at Beginning of Period		-		-
Cash and Cash Equivalents at End of Period	$	-	$	215
SUPPLEMENTAL DISCLOSURE				
Cash Paid for Interest, Net of Capitalized Amounts	$	13,988	$	15,192
Net Cash Paid (Received) for Income Taxes		(252)		30,486
Noncash Acquisitions Under Capital Leases		1,178		193
Construction Expenditures Included in Accounts Payable at September 30,		2,155		2,289

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

The condensed notes to TNC's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to TNC.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Third Quarter of 2006 Compared to Third Quarter of 2005

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

Third Quarter of 2005		$ 37
Changes in Gross Margin:		
Retail Margins	(23)	
Off-system Sales	33	
Transmission Revenues	(10)	
Other	16	
Total Change in Gross Margin		16
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	6	
Depreciation and Amortization	(11)	
Carrying Costs Income (Expense)	(29)	
Other Income	7	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(29)
Income Tax Expense		7
Third Quarter of 2006		$ 31

Net Income decreased $6 million to $31 million in 2006. The key driver of the decrease was a $29 million net increase in Operating Expenses and Other offset by a net increase in Gross Margin of $16 million and a $7 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 $23 million in comparison to 2005 primarily due to:
  - a $28 million decrease related to an increase in sharing of off-system sales margins with retail customers due to higher off-system sales. This sharing mechanism was reinstated in West Virginia effective July 1, 2006 in conjunction with our West Virginia rate case. Retail Margins further decreased due to;
  - a $13 million decrease in revenues related to financial transmission rights, net of congestion, primarily due to fewer transmission constraints in the PJM market partially offset by;
  -

a $19 million increase in fuel recovery caused by the activation of the West Virginia fuel clause in July 2006.

- Off-system Sales increased $33 million primarily due to $19 million increase in physical sales margins and an $18 million increase from lower sharing of off-system sales margins under the SIA slightly offset by a $3 million decrease in margins from optimization activities. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- Transmission Revenues decreased $10 million primarily due to the elimination of SECA revenues as of April 1, 2006. 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 3.
- Other revenue increased $16 million primarily due to a write off 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 3.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $6 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. This decrease was partially offset by a write off of deferred maintenance expenses associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.
- Depreciation and Amortization expenses increased $11 million primarily due to a write off of previously deferred depreciation expenses associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.
- Carrying Costs Income (Expense) decreased $29 million primarily due to a write off of previously recorded carrying costs income associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.
- Other Income increased $7 million primarily due to interest income related to an increase in Advances to Affiliates and an increase in allowance for funds during construction (AFUDC).

Income Taxes

The decrease in Income Tax Expense of $7 million is primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by an increase in state income taxes.

<u>Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005</u>

Reconciliation of Nine Months Ended September 30, 2005 to Nine Months Ended September 30, 2006 Net Income (in millions)

Nine Months Ended September 30, 2005		$ 108
Changes in Gross Margin:		
Retail Margins	12	
Off-system Sales	34	
Transmission Revenues	(27)	
Other	15	
Total Change in Gross Margin		34

Changes in Operating Expenses and Other:		
Other Operation and Maintenance	9	
Depreciation and Amortization	(11)	
Taxes Other Than Income Taxes	1	
Carrying Costs Income (Expense)	(19)	
Other Income	12	
Interest Expense	(13)	
Total Change in Operating Expenses and Other		(21)
Income Tax Expense		(7)
Nine Months Ended September 30, 2006		$ 114

Net Income increased $6 million to $114 million in 2006. The key driver of the increase was a $34 million net increase in Gross Margin offset by a $21 million net increase in Operating Expenses and Other and a $7 million increase in Income Tax Expense.

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

- Retail Margins increased $12 million in comparison to 2005 primarily due to:
  - a $16 million increase in retail revenues primarily related to two new industrial customers;
  - a $14 million reduction in capacity settlement payments under the Interconnection Agreement due to our lower member load ratio (MLR) share and our increased generation capacity and;
  - an $11 million increase in revenues related to financial transmission rights, net of congestion. The increase in financial transmission rights revenue is due to improved management of price risk related to serving retail load under current transmission constraints. Retail Margin increases were partially offset by;
  - a $28 million decrease related to an increase in sharing of off-system sales margins with retail customers due to higher off-system sales. This sharing mechanism was reinstated in West Virginia effective July 1, 2006 in conjunction with our West Virginia rate case.
- Off-system Sales increased $34 million primarily due to $42 million increase in physical sales margins and a $22 million increase from lower sharing of off-system sales margins under the SIA offset by a $30 million decrease in margins from optimization activities. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- Transmission Revenues decreased $27 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $5 million 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 3.
- Other revenue increased $15 million primarily due to a write off of previously deferred gains on sales of allowances associated with the E&R case and higher gains on sales of allowances. See “APCo Virginia Environmental and Reliability Costs” section of Note 3.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $9 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, partially offset by a write off of previously deferred maintenance expenses associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.

· Depreciation and Amortization expenses increased $11 million primarily due to a write off of previously deferred depreciation expenses associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.
· Carrying Costs Income (Expense) decreased $19 million primarily due to write off of previously recorded carrying costs income associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.
· Other Income increased $12 million primarily due to interest income related to an increase in Advances to Affiliates and an increase in AFUDC.
· Interest Expense increased $13 million primarily due to long-term debt issuances in 2006, partially offset by an increase in allowance for borrowed funds used during construction and a write off of previously deferred AFUDC associated with the E&R case. See "APCo Virginia Environmental and Reliability Costs" section of Note 3.

Income Taxes

The increase in Income Tax Expense of $7 million is primarily due to an increase in pretax book income and state income taxes offset in part by changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the nine months ended September 30, 2006 and 2005 were as follows:

	2006	**2005**
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,741	$ 1,543
Net Cash Flows From (Used For):		
Operating Activities	436,795	180,504
Investing Activities	(725,650)	(479,420)
Financing Activities	288,363	298,938
Net Increase (Decrease) in Cash and Cash Equivalents	(492)	22
Cash and Cash Equivalents at End of Period	$ 1,249	$ 1,565

Operating Activities

Net Cash Flows From Operating Activities were $437 million in 2006. We produced Net Income of $114 million during the period and a noncash expense item of $158 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had no significant items.

Net Cash Flows From Operating Activities were $181 million in 2005. We produced Net Income of $108 million during the period and a noncash expense item of $147 million for Depreciation and Amortization partially offset by Pension Contributions to Qualified Plan Trusts of $60 million. The other changes in assets and liabilities represent items that had a prior period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital had no significant items.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our construction expenditures of $633 million and $422 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades for both periods. In 2006 and 2005, capital projects for transmission expenditures primarily relate to the Wyoming-Jacksons Ferry 765 kV line placed in service in June 2006. Environmental upgrades include the flue gas desulphurization (FGD) projects at the Amos and Mountaineer Plants. For the remainder of 2006, we expect $300 million of construction expenditures. In addition, we invested $94 million and $68 million into the Utility Money Pool in 2006 and 2005, respectively.

Financing Activities

Net Cash Flows From Financing Activities were $288 million in 2006. We issued $500 million in Senior Unsecured Notes and $50 million in Pollution Control Bonds. We also retired a First Mortgage Bond of $100 million. We repaid short-term borrowings from the Utility Money Pool of $194 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 $18 million. See “Coal Contract Amendment” within “Significant Factors” for additional information.

Net Cash Flows From Financing Activities were $299 million in 2005. We issued four Senior Unsecured Notes totaling $850 million. We also issued Notes Payable - Affiliates of $100 million and received a capital contribution from our parent of $150 million. We retired $450 million of Senior Unsecured Notes and three First Mortgage Bonds totaling $125 million. In addition, we repaid $211 million of advances from the Utility Money Pool.

Financing Activity

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

<u>Issuances</u>

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	250,000	5.55	2011
Senior Unsecured Notes		250,000	6.375	2036

Pollution Control Bonds		50,275	Variable	2036

Retirements

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
First Mortgage Bonds	$	100,000	6.80	2006
Other Debt		8	13.718	2026

In November 2006, we issued $17.5 million of variable rate Pollution Control Bonds and retired $17.5 million, 2.70% pollution control bonds due in 2007.

In November 2006, we had a required remarketing of $30 million of 2.80% Pollution Control Bonds, which were converted from a three-year fixed rate mode to an auction rate mode.

Liquidity

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

Summary Obligation Information

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

Significant Factors

Coal Contract Amendment

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

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

Since there are no further requirements related to the liquidation of the shortfall tons, we recognized the $12 million shortfall payment in the first quarter of 2006. We recorded a $5 million reduction in Regulatory Assets on our Condensed Consolidated Balance Sheet and recorded the remaining $7 million as a reduction to Fuel and Other

Consumables for Electric Generation on our Condensed Consolidated Statement of Income. We recorded the $68 million payment within Deferred Credits and Other on our Condensed Consolidated Balance Sheet. To the extent tons are received, payment of the higher contracted price per ton will effectively result in a repayment of funds to the coal supplier.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters and Note 5 - Commitments and Contingencies in the “Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries” section. 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 for additional discussion of factors relevant to us.

Critical Accounting Estimates

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of September 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 85,654	$ 7,481	$ -	$ 93,135
Noncurrent Assets	107,705	510	-	108,215
Total MTM Derivative Contract Assets	193,359	7,991	-	201,350
Current Liabilities	(64,432)	(1,979)	(1,881)	(68,292)
Noncurrent Liabilities	(70,002)	(699)	(9,138)	(79,839)
Total MTM Derivative Contract Liabilities	(134,434)	(2,678)	(11,019)	(148,131)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 58,925	$ 5,313	$ (11,019)	$ 53,219

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 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	(6,079)
Fair Value of New Contracts at Inception When Entered During the Period (a)	121
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(315)
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)	6,107
Changes due to SIA Agreement (c)	(6,533)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	8,901

Total MTM Risk Management Contract Net Assets		58,925
Net Cash Flow & Fair Value Hedge Contracts		5,313
DETM Assignment (e)		(11,019)
Total MTM Risk Management Contract Net Assets at September 30, 2006	$	53,219

(a) Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
(d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(e) See “Natural Gas Contracts with DETM” section of Note 17 of the 2005 Annual Report.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2006
(in thousands)

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted - Exchange Traded Contracts	$ 1,794	$ 12,885	$ 4,663	$ -	$ -	$ -	$ 19,342
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4,076	11,246	4,922	7,304	-	-	27,548
Prices Based on Models and Other Valuation Methods (b)	(43)	(4,690)	1,149	4,648	8,331	2,640	12,035
Total	$ 5,827	$ 19,441	$ 10,734	$ 11,952	$ 8,331	$ 2,640	$ 58,925

(a) “Prices Provided by Other External Sources - OTC Broker Quotes” reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) “Prices Based on Models and Other Valuation Methods” is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying

commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to September 30, 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
Nine Months Ended September 30, 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	4,482	-	4,951	9,433
Impact due to Changes in SIA (a)	(442)	-	-	(442)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	2,261	5	1,757	4,023
Ending Balance in AOCI September 30, 2006	$ 4,821	$ (166)	$ (8,062)	$ (3,407)

(a) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,919 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 September 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Nine Months Ended September 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$655	$1,915	$683	$365	$732	$1,216	$579	$209

The High VaR for the nine months ended September 30, 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 $141 million and $142 million at September 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2006 and 2005