AMERICAN ELECTRIC POWER CO INC
Form 10-Q
November 02, 2007

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, 2007**
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
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
1-6543	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 Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan 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

Columbus Southern Power Company, Indiana Michigan 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, 2007
American Electric Power Company, Inc.	400,006,022
	($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)
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, 2007

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan 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
ADITC	Accumulated Deferred Investment Tax Credits.
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
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.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income (Loss).
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
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.).
CTC	Competition Transition Charge.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOJ	United States Department of Justice.
E&R	Environmental compliance and transmission and distribution system reliability.
EDFIT	Excess Deferred Federal Income Taxes.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.

FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46	FIN 46, "Consolidation of Variable Interest Entities."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company, a former AEP subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
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.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO, SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RSP	Ohio 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 Financial Accounting Standards Board.
SFAS 71	

	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill 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.
Turk Plant	John W. Turk Jr. Plant.
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 and performance 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 (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into RTOs.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

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

EXECUTIVE OVERVIEW

Regulatory Activity

The status of base rate filings ongoing or finalized this year with implemented rates are:

Operating Company	Jurisdiction	Revised Annual Rate Increase Request	Implemented Annual Rate Increase	Projected or Effective Date of Rate Increase	Date of Final Order
		(in millions)			
APCo	Virginia	$ 198(a)	$ 24(a)	October 2006	May 2007
OPCo	Ohio	8	4(b)	May 2007	October 2007
CSPCo	Ohio	24	19(b)	May 2007	October 2007
TCC	Texas	70	47	June 2007	October 2007
TNC	Texas	22	14	June 2007	May 2007
PSO	Oklahoma	48	10(c)	July 2007	October 2007
OPCo	Ohio	12	NA	January 2008	NA
CSPCo	Ohio	35	NA	January 2008	NA

(a) The difference between the requested and implemented amounts of annual rate increase is partially offset by approximately $35 million of incremental E&R costs which APCo has reflected as a regulatory asset. APCo will file for recovery through the E&R surcharge mechanism in 2008. APCo also implemented, beginning September 1, 2007 subject to refund, a net $50 million reduction in credits to customers for off-system sales margins as part of its July 2007 fuel clause filing under the new re-regulation legislation.
(b) Management plans to seek rehearing of the PUCO decision.
(c) Implemented $9 million in July 2007, increased to $10 million upon OCC order in October 2007.

In Virginia, APCo filed the following non-base rate requests in July 2007 with the Virginia SCC:

Operating Company	Jurisdiction	Cost Type	Request	Implemented Annual Rate Increase	Projected or Effective Date of Rate Increase	Date of Final Order
			(in millions)			
APCo	Virginia	Incremental E&R	$ 60	$ NA	December 2007	NA
APCo	Virginia	Fuel, Off-system Sales	33	33 (a)	September 2007	(a)

(a) Subject to refund. Proceeding is on-going.

Ohio Restructuring

As permitted by the current Ohio restructuring legislation, CSPCo and OPCo can implement market-based rates effective January 2009, following the expiration of its RSPs on December 31, 2008. In August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. In place of market-based rates, it is more likely that some form of cost-based rates or hybrid-based rates would be required. The legislation passed through the Ohio Senate and still must be considered by the Ohio House of Representatives. Management continues to analyze the proposed legislation and is working with various stakeholders to achieve a principled, fair and well-considered approach to electric supply pricing. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009.

SWEPCo and PSO Construction Costs

SWEPCo has incurred pre-construction and equipment procurement costs of $206 million and $15 million related to its Turk and Stall plant construction projects, respectively. In September 2007, the PUCT staff recommended that SWEPCo's application to build the Turk Plant be denied suggesting the construction of the plant would adversely impact the development of competition in the SPP zone. In the filings to date, both the APSC and LPSC staffs have supported the Turk Plant project. Neither the PUCT, the APSC nor the LPSC have issued final orders regarding the Turk Plant.

PSO has deferred pre-construction costs of $20 million related to its Red Rock Generating Facility construction project. In October 2007, the OCC issued a final order denying PSO's application for pre-approval of the Red Rock project stating PSO failed to fully study other alternatives. PSO has cancelled the project and intends to seek recovery of the $20 million.

Michigan Depreciation Study Filing

In September 2007, the Michigan Public Service Commission (MPSC) approved a settlement agreement authorizing I&M to implement new book depreciation rates. Based on the depreciation study included in the settlement, I&M agreed to decrease pretax annual depreciation expense, on a Michigan jurisdictional basis, by approximately $10 million. This petition was not a request for a change in retail customers' electric service rates. In addition and as a result of the new MPSC-approved rates, I&M will decrease pretax annual depreciation expense, on a FERC jurisdictional basis, by approximately $11 million which will reduce wholesale rates for customers representing approximately half the load beginning in November 2007 and reduce wholesale rates for the remaining customers in June 2008.

Dividend Increase

In October 2007, our Board of Directors approved a five percent increase in our quarterly dividend to $0.41 per share from $0.39 per share.

Investment Activity

In September 2007, AEGCo purchased the partially completed 580 MW Dresden Plant from Dominion Resources, Inc. for $85 million and the assumption of liabilities of $2 million. Management estimates that approximately $180 million in additional costs (excluding AFUDC) will be required to finish the construction of the plant.

In October 2007, we sold our 50% equity interest in the Sweeny Cogeneration Plant (Sweeny) to ConocoPhillips for approximately $80 million, including working capital and the buyer's assumption of project debt. In addition to the sale of our interest in Sweeny, we agreed to separately sell our purchase power contract for our share of power generated by Sweeny through 2014 for $11 million to ConocoPhillips. ConocoPhillips also agreed to assume certain related third-party power obligations. In the fourth quarter of 2007, we estimate that we will realize a total of $57 million in pretax gains related to the sales of our investment in the Sweeny Plant and the related purchase power contracts.

Environmental Litigation

In October 2007, we announced that we had reached a settlement agreement with the Federal EPA, the DOJ, various states and special interest groups. Under the New Source Review (NSR) settlement agreement, we agreed to invest in additional environmental controls for our plants before 2019. We will also pay a $15 million civil penalty and provide $36 million for environmental projects coordinated with the federal government and $24 million to the states for environmental mitigation. In the third quarter of 2007, we expensed $77 million (before tax) related to the penalty and the environmental mitigation projects.

RESULTS OF OPERATIONS

Our principal operating business segments and their related business activities are as follows:

Utility Operations

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

MEMCO Operations

- Barging operations that annually transport approximately 34 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Approximately 35% of the barging operations relates to the transportation of coal, 30% relates to agricultural products, 18% relates to steel and 17% relates to other commodities.

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities primarily in ERCOT. Our 50% interest in the Sweeny Cogeneration Plant was sold in October 2007.

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss for the three and nine months ended September 30, 2007 and 2006. We reclassified prior year amounts to conform to the current year's segment presentation.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in millions)			
Utility Operations	$ 388	$ 378	$ 879	$ 902
MEMCO Operations	18	19	40	54
Generation and Marketing	3	4	17	10
All Other (a)	(2)	(136)	(1)	(151)
Income Before Discontinued Operations and Extraordinary Loss	$ 407	$ 265	$ 935	$ 815

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.

- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in the fourth quarter of 2006.

Third Quarter of 2007 Compared to Third Quarter of 2006

Income Before Discontinued Operations and Extraordinary Loss in 2007 increased $142 million compared to 2006 primarily due to a $136 million after-tax impairment of the Plaquemine Cogeneration Facility recorded in August 2006.

Average basic shares outstanding for the three-month period increased to 399 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation plans. At September 30, 2007, actual shares outstanding were 400 million.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Income Before Discontinued Operations and Extraordinary Loss in 2007 increased $120 million compared to 2006 primarily due to a $136 million after-tax impairment of the Plaquemine Cogeneration Facility recorded in 2006. This increase was partially offset by a decrease in earnings of $23 million from our Utility Operations segment. The decrease in Utility Operations segment earnings primarily relates to higher operation and maintenance expenses due to the NSR settlement, higher regulatory amortization expense, higher interest expense and lower earnings-sharing payments from Centrica received in March 2007, representing the last payment under an earnings-sharing agreement. These decreases in earnings were partially offset by rate increases, increased residential and commercial usage and customer growth and favorable weather.

Average basic shares outstanding for the nine-month period increased to 398 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation plans. At September 30, 2007, actual shares outstanding were 400 million.

Utility Operations

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

Utility Operations Income Summary
For the Three and Nine Months Ended September 30, 2007 and 2006

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in millions)			
Revenues	$ 3,600	$ 3,437	$ 9,587	$ 9,199
Fuel and Purchased Power	1,413	1,384	3,641	3,633
Gross Margin	2,187	2,053	5,946	5,566
Depreciation and Amortization	374	374	1,122	1,060
Other Operating Expenses	1,037	962	2,985	2,781
Operating Income	776	717	1,839	1,725
Other Income, Net	27	18	72	103

Interest Charges and Preferred Stock Dividend Requirements	213	160	599	475
Income Tax Expense	202	197	433	451
Income Before Discontinued Operations and Extraordinary Loss	$ 388	$ 378	$ 879	$ 902

Summary of Selected Sales and Weather Data
For Utility Operations
For the Three and Nine Months Ended September 30, 2007 and 2006

	Three Months Ended September 30,		Nine Months Ended September 30,	
Energy/Delivery Summary	**2007**	**2006**	**2007**	**2006**
	(in millions of KWH)			
Energy				
Retail:				
Residential	13,749	13,482	38,015	36,010
Commercial	11,164	10,799	30,750	29,149
Industrial	14,697	13,468	43,110	40,405
Miscellaneous	686	719	1,932	1,991
Total Retail	40,296	38,468	113,807	107,555
Wholesale	13,493	13,464	31,648	35,132
Delivery				
Texas Wires – Energy delivered to customers served by AEP's Texas Wires Companies	7,721	7,877	20,297	20,338
Total KWHs	61,510	59,809	165,752	163,025

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.

Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Nine Months Ended September 30, 2007 and 2006

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(in degree days)			
Weather Summary				
Eastern Region				
Actual – Heating (a)	2	10	2,041	1,573
Normal – Heating (b)	7	7	1,973	1,999
Actual – Cooling (c)	808	685	1,189	914
Normal – Cooling (b)	685	688	963	970
Western Region (d)				

Actual – Heating (a)	0	0	994	664
Normal – Heating (b)	2	2	993	1,007
Actual – Cooling (c)	1,406	1,468	2,084	2,325
Normal – Cooling (b)	1,411	1,410	2,084	2,079

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

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Third Quarter of 2006		$ 378
Changes in Gross Margin:		
Retail Margins	155	
Off-system Sales	36	
Transmission Revenues, Net	(58)	
Other Revenues	1	
Total Change in Gross Margin		134
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(69)	
Taxes Other Than Income Taxes	(6)	
Carrying Costs Income	11	
Other Income, Net	(2)	
Interest and Other Charges	(53)	
Total Change in Operating Expenses and Other		(119)
Income Tax Expense		(5)
Third Quarter of 2007		$ 388

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $10 million to $388 million in 2007. The key driver of the increase was a $134 million increase in Gross Margin partially offset by a $119 million increase in Operating Expenses and Other and a $5 million increase in Income Tax Expense.

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

· Retail Margins increased $155 million primarily due to the following:
  · A $29 million increase at APCo related to the Virginia base rate case and the West Virginia construction surcharge.
  · A $29 million increase related to Ormet, a new industrial customer in Ohio, effective January 1, 2007. See “Ormet” section of Note 3.

- A $23 million increase related to increased residential and commercial usage and customer growth.
- A $16 million increase in usage related to weather. As compared to the prior year, our eastern region experienced an 18% increase in cooling degree days partially offset by a 4% decrease in cooling degree days in our western region.
- A $15 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs.
- A $15 million increase related to new rates in Texas.
- A $14 million increase related to increased sales to municipal, cooperative and other customers primarily resulting from new power supply contracts.

These increases were partially offset by:

- A $15 million decrease in financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market. Financial transmission rights are financial instruments which entitle the holder to receive compensation for transmission charges that arise when the PJM market is congested.

- Margins from Off-system Sales increased $36 million primarily due to favorable fuel reconciliations in our western territory, benefits from our eastern natural gas fleet, higher power prices, and higher sales volumes in the east.
- Transmission Revenues, Net decreased $58 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.
- Other Revenues were essentially flat as a result of higher securitization revenue at TCC from the $1.7 billion securitization in October 2006 partially offset by lower gains on sale of emission allowances. Securitization revenue represents amounts collected to recover securitization bond principal and interest payments related to TCC's securitized transition assets and are fully offset by amortization and interest expenses.

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

- Other Operation and Maintenance expenses increased $69 million primarily due to the NSR settlement partially offset by an abandonment of digital turbine control equipment at the Cook Plant recorded in the prior year. See "Federal EPA Complaint and Notice of Violation" section in Note 4.
- Depreciation and Amortization expense was flat as a result of increased Texas amortization of the securitized transition assets and overall higher depreciable property balances, offset by lower depreciation expense at I&M and APCo. The decrease at I&M relates to the lower depreciation rates approved by the IURC in June 2007. The decrease at APCo relates to the lower depreciation rates approved by the Virginia SCC in May 2007 and adjustments in the prior period related to the 2006 Virginia E&R case.
- Carrying Costs Income increased $11 million primarily due to higher carrying cost income related to APCo's Virginia E&R cost deferrals offset by TCC's start in recovering stranded costs in October 2006, thus eliminating future TCC carrying costs income.
- Interest and Other Charges increased $53 million primarily due to additional debt issued in the twelve months ended September 30, 2007 including TCC securitization bonds as well as higher rates on variable rate debt.
- Income Tax Expense increased $5 million due to an increase in pretax income.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2006		$	902
Changes in Gross Margin:			
Retail Margins	383		
Off-system Sales	49		
Transmission Revenues, Net	(87)		
Other Revenues	35		
Total Change in Gross Margin			380
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(154)		
Gain on Dispositions of Assets, Net	(47)		
Depreciation and Amortization	(62)		
Taxes Other Than Income Taxes	(3)		
Carrying Costs Income	(28)		
Other Income, Net	(3)		
Interest and Other Charges	(124)		
Total Change in Operating Expenses and Other			(421)
Income Tax Expense			18
Nine Months Ended September 30, 2007		$	879

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss decreased $23 million to $879 million in 2007. The key driver of the decrease was a $421 million increase in Operating Expenses and Other, offset by a $380 million increase in Gross Margin and an $18 million decrease in Income Tax Expense.

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

· Retail Margins increased $383 million primarily due to the following:

  · An $84 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a $51 million increase related to new rates implemented in our other east jurisdictions of Virginia, West Virginia and Kentucky and a $23 million increase related to new rates in Texas and a $9 million increase related to new rates in Oklahoma.
  · A $93 million increase related to increased residential and commercial usage and customer growth.
  · An $83 million increase in usage related to weather. As compared to the prior year, our eastern region and western region experienced 30% and 50% increases, respectively, in heating degree days. Also, our eastern region experienced a 30% increase in cooling degree days which was offset by a 10% decrease in cooling degree days in our western region.
  · A $66 million increase related to Ormet, a new industrial customer in Ohio, effective January 1, 2007. See "Ormet" section of Note 3.
  · A $35 million increase related to increased sales to municipal, cooperative and other wholesale customers primarily resulting from new power supply contracts.

  These increases were partially offset by:

  ·

- A $63 million decrease in financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market.
- A $25 million decrease due to a second quarter 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding. See "SWEPCo Fuel Reconciliation – Texas" section of Note 3.
- A $14 million decrease related to increased PJM ancillary costs.

- Margins from Off-system Sales increased $49 million primarily due to strong trading performance and favorable fuel reconciliations in our western territory.
- Transmission Revenues, Net decreased $87 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.
- Other Revenues increased $35 million primarily due to higher securitization revenue at TCC resulting from the $1.7 billion securitization in October 2006. Securitization revenue represents amounts collected to recover securitization bond principal and interest payments related to TCC's securitized transition assets and are fully offset by amortization and interest expenses.

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

- Other Operation and Maintenance expenses increased $154 million primarily due to a $77 million expense resulting from the NSR settlement. The remaining increases relate to generation expenses from plant outages and base operations and distribution expenses associated with service reliability and storm restoration primarily in Oklahoma.
- Gain on Disposition of Assets, Net decreased $47 million primarily related to the earnings sharing agreement with Centrica from the sale of our REPs in 2002. In 2006, we received $70 million from Centrica for earnings sharing and in 2007 we received $20 million as the earnings sharing agreement expired.
- Depreciation and Amortization expense increased $62 million primarily due to increased Ohio regulatory asset amortization related to recovery of IGCC pre-construction costs, increased Texas amortization of the securitized transition assets and higher depreciable property balances, partially offset by commission-approved lower depreciation rates in Indiana and Virginia.
- Carrying Costs Income decreased $28 million primarily due to TCC's start in recovering stranded costs in October 2006, thus eliminating future TCC carrying costs income, offset by higher carrying costs income related to APCo's Virginia E&R cost deferrals.
- Interest and Other Charges increased $124 million primarily due to additional debt issued in the twelve months ended September 30, 2007 including TCC securitization bonds as well as higher rates on variable rate debt.
- Income Tax Expense decreased $18 million due to a decrease in pretax income.

MEMCO Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Income Before Discontinued Operations and Extraordinary Loss from our MEMCO Operations segment decreased from $19 million in 2006 to $18 million in 2007. Operating expenses increased $2 million mainly due to the increased fleet size, rising fuel costs and wage increases.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Income Before Discontinued Operations and Extraordinary Loss from our MEMCO Operations segment decreased from $54 million in 2006 to $40 million in 2007. MEMCO operated approximately 11% more barges in the first nine months of 2007 than 2006; however, revenue remained flat as reduced imports, primarily steel and cement continued to depress freight rates and reduce northbound loadings. Operating expenses were up for the first nine months of 2007 compared to 2006 primarily due to the cost of the increased fleet size, rising fuel costs and wage increases.

Generation and Marketing

Third Quarter of 2007 Compared to Third Quarter of 2006

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment slightly decreased from $4 million in 2006 to $3 million in 2007. The decrease was primarily due to increased purchased power and operating expenses. The decrease was partially offset by increases in revenues primarily due to certain existing ERCOT energy contracts, which were transferred from our Utility Operations segment on January 1, 2007, and favorable marketing contracts with municipalities and cooperatives in ERCOT.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased from $10 million in 2006 to $17 million in 2007. Revenues increased primarily due to certain existing ERCOT energy contracts, which were transferred from our Utility Operations segment on January 1, 2007, and favorable marketing contracts with municipalities and cooperatives in ERCOT. The increase in revenues was partially offset by increased purchased power and operating expenses.

All Other

Third Quarter of 2007 Compared to Third Quarter of 2006

Loss Before Discontinued Operations and Extraordinary Loss from All Other decreased from $136 million in 2006 to $2 million in 2007. The decrease was primarily due to a $136 million after-tax impairment of the Plaquemine Cogeneration Facility recorded in August 2006.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Loss Before Discontinued Operations and Extraordinary Loss from All Other decreased from $151 million in 2006 to $1 million in 2007. In 2006, we recorded a $136 million after-tax impairment of the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. In 2007, we had an after-tax gain of $10 million on the sale of investment securities.

AEP System Income Taxes

Income Tax Expense increased $72 million in the third quarter of 2007 compared to the third quarter of 2006 primarily due to an increase in pretax book income.

Income Tax Expense increased $49 million for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006 primarily due to an increase 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

	September 30, 2007		December 31, 2006	
	($ in millions)			
Long-term Debt, Including Amounts Due Within One Year	$ 14,776	58.3%	$ 13,698	59.1%
Short-term Debt	587	2.3	18	0.0
Total Debt	15,363	60.6	13,716	59.1
Common Equity	9,909	39.1	9,412	40.6
Preferred Stock	61	0.3	61	0.3
Total Debt and Equity Capitalization	$ 25,333	100.0%	$ 23,189	100.0%

Our ratio of debt to total capital increased, as planned, from 59.1% to 60.6% in 2007 due to our increased borrowings to support our construction program.

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, 2007, our available liquidity was approximately $2.6 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,500	April 2012
Total	3,000	
Cash and Cash Equivalents	196	
Total Liquidity Sources	3,196	
Less: AEP Commercial Paper Outstanding	559	
Letters of Credit Drawn	69	
Net Available Liquidity	$ 2,568	

In 2007, we amended the terms and extended the maturity of our two credit facilities by one year to March 2011 and April 2012, respectively. The facilities are structured as two $1.5 billion credit facilities of which $300 million may be issued under each credit facility as letters of credit.

Sale of Receivables

In October 2007, we renewed our sale of receivables agreement. The sale of receivables agreement provides a commitment of $650 million from a bank conduit to purchase receivables. Under the agreement, the commitment will increase to $700 million for the months of August and September to accommodate seasonal demand. This agreement expires in October 2008.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined in our revolving credit agreements. At September 30, 2007, this contractually-defined percentage was 56.3%. Nonperformance of these covenants could result in an event of default under these credit agreements. At September 30, 2007, 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 major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

The two revolving credit facilities do not permit the lenders to refuse a draw on either facility if a material adverse change occurs.

Under a regulatory order, our utility subsidiaries, other than TCC, cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% of its capital. In addition, this order restricts those utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At September 30, 2007, all applicable utility subsidiaries complied with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At September 30, 2007, we had not exceeded those authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2007 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.

<u>Cash Flow</u>

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

	Nine Months Ended September 30,			
	2007		**2006**	
	(in millions)			
Cash and Cash Equivalents at Beginning of Period	$	301	$	401
Net Cash Flows From Operating Activities		1,630		2,196
Net Cash Flows Used For Investing Activities		(2,935)		(2,457)

Net Cash Flows From Financing Activities		1,200		119
Net Decrease in Cash and Cash Equivalents		(105)		(142)
Cash and Cash Equivalents at End of Period	$	196	$	259

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of September 30, 2007, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2007 was $865 million. The weighted-average interest rate of our commercial paper for the nine months ended September 30, 2007 was 5.6%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

	Nine Months Ended September 30,			
		2007		**2006**
	(in millions)			
Net Income	$	858	$	821
Less: Discontinued Operations, Net of Tax		(2)		(6)
Income Before Discontinued Operations		856		815
Depreciation and Amortization		1,144		1,084
Other		(370)		297
Net Cash Flows From Operating Activities	$	1,630	$	2,196

Net Cash Flows From Operating Activities decreased in 2007 primarily due to lower fuel costs recovery, higher tax payments in 2007 in conjunction with the filing of the 2006 tax return and increased customer accounts receivable reflecting September 2007 weather's impact on sales and new contracts in the Generation and Marketing segment.

Net Cash Flows From Operating Activities were $1.6 billion in 2007. We produced Income Before Discontinued Operations of $856 million adjusted for noncash expense items, primarily depreciation and amortization. Other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items, the most significant of which relates to the Texas CTC refund of fuel over-recovery.

Net Cash Flows From Operating Activities were $2.2 billion in 2006. We produced Income Before Discontinued Operations of $815 million adjusted for noncash expense items, primarily depreciation and amortization. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. Under-recovered fuel costs decreased due to recovery of higher cost of fuel, especially natural gas. Other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant is a $235 million decrease in cash related to customer deposits held for trading activities generally due to lower gas and power market prices.

Investing Activities

	Nine Months Ended September 30,			
	2007		2006	
	(in millions)			
Construction Expenditures	$	(2,595)	$	(2,428)
Acquisition of Darby, Dresden and Lawrenceburg Plants		(512)		-
Proceeds from Sales of Assets		78		120
Other		94		(149)
Net Cash Flows Used For Investing Activities	$	(2,935)	$	(2,457)

Net Cash Flows Used For Investing Activities were $2.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan and purchases of gas-fired generating units.

Net Cash Flows Used For Investing Activities were $2.5 billion in 2006 primarily due to Construction Expenditures for our environmental investment plan, consistent with our budgeted cash flows.

We forecast approximately $1 billion of construction expenditures for the remainder of 2007. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded with cash from operations and financing activities.

Financing Activities

	Nine Months Ended September 30,			
	2007		2006	
	(in millions)			
Issuance/Retirement of Debt, Net	$	1,623	$	529
Dividends Paid on Common Stock		(467)		(437)
Other		44		27
Net Cash Flows From Financing Activities	$	1,200	$	119

Net Cash Flows From Financing Activities in 2007 were $1.2 billion primarily due to issuing $1.9 billion of debt securities including $1 billion of new debt for plant acquisitions and construction and increasing short-term commercial paper borrowings. We paid common stock dividends of $467 million. See Note 9 for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows From Financing Activities in 2006 were $119 million. During 2006, we issued $115 million of obligations relating to pollution control bonds, issued $1 billion of senior unsecured notes and retired $396 million of notes for a net increase in notes outstanding of $604 million and retired $100 million of first mortgage bonds and $52 million of securitization bonds.

We expect to issue debt in the capital markets of approximately $675 million to fund our capital investment plans for the remainder of 2007.

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 internal 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 are as follows:

	September 30, 2007	December 31, 2006
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 530	$ 536
Rockport Plant Unit 2 Future Minimum Lease Payments	2,290	2,364
Railcars Maximum Potential Loss From Lease Agreement	30	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 2006 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2006 Annual Report and has not changed significantly from year-end other than the debt issuances discussed in "Cash Flow" and "Financing Activities" above and the obligations resulting from the settlement agreement regarding alleged violations of the NSR provisions of the CAA. See "Federal EPA Complaint and Notice of Violations" section of Note 4. We also entered into additional contractual commitments related to the construction of the proposed Turk Plant announced in August 2006. See "Turk Plant" in the "Arkansas Rate Matters" section of Note 3.

Other

Texas REPs

As part of the purchase-and-sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. We received $20 million and $70 million payments in 2007 and 2006, respectively, for our share in earnings. The payment we received in 2007 was the final payment under the earnings sharing agreement.

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 2006 Annual Report. The 2006 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 2006 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition.

Ohio Restructuring

As permitted by the current Ohio restructuring legislation, CSPCo and OPCo can implement market-based rates effective January 2009, following the expiration of its RSPs on December 31, 2008. In August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. In place of market-based rates, it is more likely that some form of cost-based rates or hybrid-based rates would be required. The legislation passed through the Ohio Senate and still must be considered by the Ohio House of Representatives. Management continues to analyze the proposed legislation and is working with various stakeholders to achieve a principled, fair and well-considered approach to electric supply pricing. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009.

Texas Restructuring

TCC recovered its net recoverable stranded generation costs through a securitization financing and is refunding its net other true-up items through a CTC rate rider credit under 2006 PUCT orders. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items.

Municipal customers and other intervenors also appealed the PUCT true-up and related orders seeking to further reduce TCC's true-up recoveries. In March 2007, the Texas District Court judge hearing the appeal of the true-up order affirmed the PUCT's April 4, 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. However, the District Court did not rule that the carrying cost rate was inappropriate. If the District Court's ruling on the carrying cost rate is ultimately upheld on appeal and remanded to the PUCT for reconsideration, the PUCT could either confirm the existing weighted average carrying cost (WACC) rate or determine a new rate. If the PUCT reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

The District Court judge also determined the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. If upheld on appeal, this ruling could have a materially favorable effect on TCC's results of operations and cash flows.

TCC, the PUCT and intervenors appealed the District Court true-up order rulings to the Texas Court of Appeals. Management cannot predict the outcome of these true-up and related proceedings. If TCC ultimately succeeds in its appeals in both state and federal court, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, or if TCC has a tax normalization violation as discussed in the "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" section of Note 3, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

Virginia Restructuring

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation and supply rates. These amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation and supply will return to cost-based regulation in lieu of market-based rates. The legislation provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investments, (b) demand side management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments; significant return on equity enhancements for investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. The new re-regulation legislation should result in significant positive effects on APCo's future earnings and cash flows from the mandated enhanced future returns on equity, the reduction of regulatory lag from the opportunities to adjust base rates on a biennial basis and the new opportunities to request timely recovery of certain new costs not included in base rates.

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP and other transmission owners in the region covered by PJM and MISO eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. Approximately $10 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of the AEP East companies’ SECA customers. The AEP East companies reached settlements with certain SECA customers related to approximately $69 million of such revenues for a net refund of $3 million. The AEP East companies are in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and will consume about $7 million of the reserves for refunds, leaving approximately $115 million of contested SECA revenues and $30 million of refund reserves. If the ALJ’s initial decision were upheld in its entirety, it would disallow approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on recent settlement experience and the expectation that most of the $115 million of unsettled SECA revenues will be settled, management believes that the remaining reserve of $30 million will be adequate to cover all remaining settlements.

In September 2006, AEP, together with Exelon Corporation and The Dayton Power and Light Company, filed an extensive post-hearing brief and reply brief noting exceptions to the ALJ’s initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ’s findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining $115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ’s decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations, cash flows and financial condition.

PJM Marginal-Loss Pricing

On June 1, 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads. Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through September 30, 2007, AEP experienced an increase in the cost of delivering energy from the generating plant locations to customer load zones partially offset by cost recoveries and increased off-system sales resulting in a net loss of approximately $25 million. AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue through the appropriate stakeholder processes a modification of such methodology. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and is seeking recovery in current and future fuel or base rate filings as appropriate in each of its eastern zone states. In the interim, these costs will have an adverse effect on future results of operations and cash flows. Management is unable to predict whether full recovery will ultimately be approved.

New Generation

AEP is in various stages of construction of the following generation facilities. Certain plants are pending regulatory approval:

Operating Company	Project Name	Location	Total Projected Cost (a)	CWIP	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
			(in millions)	(in millions)				
SWEPCo	Mattison	Arkansas	$ 122(b)	$ 52	Gas	Simple-cycle	340 (b)	2007
PSO	Southwestern	Oklahoma	59(c)	45	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	58(c)	45	Gas	Simple-cycle	170	2008
AEGCo	Dresden (d)	Ohio	265(d)	88	Gas	Combined-cycle	580	2009
SWEPCo	Stall	Louisiana	375	15	Gas	Combined-cycle	480	2010
SWEPCo	Turk (e)	Arkansas	1,300(e)	206	Coal	Ultra-supercritical	600 (e)	2011
APCo	Mountaineer	West Virginia	2,230	-	Coal	IGCC	629	2012
CSPCo/OPCo	Great Bend	Ohio	2,230(f)	-	Coal	IGCC	629	2017

(a) Amount excludes AFUDC.
(b) Includes Units 3 and 4, 150 MW, declared in commercial operation on July 12, 2007 with construction costs totaling $55 million.
(c) In April 2007, the OCC approved that PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service at the time these units are placed in service.
(d) In September 2007, AEGCo purchased the under-construction Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(e) SWEPCo plans to own approximately 73%, or 438 MW, totaling about $950 million in capital investment. See "Turk Plant" section below.
(f) Front-end engineering and design study is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 2006 opinion and order. See "Ohio IGCC Plant" section below.

AEP acquired the following generation facilities:

Operating Company	Plant Name	Location	Cost (in millions)	Fuel Type	Plant Type	MW Capacity	Purchase Date
CSPCo	Darby (a)	Ohio	$ 102	Gas	Simple-cycle	480	April 2007
AEGCo	Lawrenceburg (b)	Indiana	325	Gas	Combined-cycle	1,096	May 2007

(a) CSPCo purchased Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company.
(b) AEGCo purchased Lawrenceburg Generating Station (Lawrenceburg), adjacent to I&M's Tanners Creek Plant, from an affiliate of Public Service Enterprise Group (PSEG). AEGCo sells the power to CSPCo under a FERC-approved unit power agreement.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the average 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo 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 a period of no more than twelve months effective July 1, 2006. Through September 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. As of September 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered.

The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs collected for pre-construction costs, associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Ohio Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio Supreme Court heard oral arguments for these appeals in October 2007. Management believes that the PUCO's authorization to begin collection of Phase 1 pre-construction costs is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase 1 cost-related recoveries.

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant have escalated to $2.2 billion. CSPCo and OPCo may need to request an extension to the 5-year start of construction requirement if the commencement of construction is delayed beyond 2011.

Red Rock Generating Facility

In July 2006, PSO announced plans to enter into an agreement with Oklahoma Gas and Electric (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit at the site of OG&E's existing Sooner Plant near Red Rock, in north central Oklahoma. PSO would own 50% of the new unit, OG&E would own approximately 42% and the Oklahoma Municipal Power Authority (OMPA) would own approximately 8%. OG&E would manage construction of the plant. OG&E and PSO requested pre-approval to construct the Red Rock Generating Facility and implement a recovery rider. In March 2007, the OCC consolidated PSO's pre-approval application with OG&E's request. The Red Rock Generating Facility was estimated to cost $1.8 billion and was expected to be in service in 2012. The OCC staff and the ALJ recommended the OCC approve PSO's and OG&E's filing. As of September 2007, PSO incurred approximately $20 million of pre-construction costs and contract cancellation fees.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but denied PSO's and OG&E's application for construction pre-approval stating PSO and OG&E failed to fully study other alternatives. Since PSO and OG&E could not obtain pre-approval to build the Red Rock Generating Facility, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. Management believes the pre-construction costs capitalized, including any cancellation fees, were prudently incurred, as evidenced by the OCC staff and the ALJ's recommendations that the OCC approve PSO's filing, and established a regulatory asset for future recovery. Management believes such pre-construction costs are probable of recovery and intends to seek full recovery of such costs in the near future. If recovery is denied, future results of operations and cash flows would be adversely affected. As a result of the OCC's decision, PSO will be re-considering various alternative options to meet its capacity needs in the future.

Turk Plant

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named Turk Plant. SWEPCo submitted filings with the Arkansas Public Service Commission (APSC) in December 2006 and the PUCT and LPSC in February 2007 to seek approvals to proceed with the plant. In September 2007, OMPA signed a joint ownership agreement and agreed to own approximately 7% of the Turk Plant. SWEPCo continues discussions with Arkansas Electric Cooperative Corporation and North Texas Electric Cooperative to become potential partners in the Turk Plant. SWEPCo anticipates owning approximately 73% of the Turk Plant and will operate the facility. The Turk Plant is estimated to cost $1.3 billion in total with SWEPCo's portion estimated to cost $950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in mid-2011. As of September 2007, SWEPCo incurred and capitalized approximately $206 million and has contractual commitments for an additional $875 million. If the Turk Plant is not approved, cancellation fees may be required to terminate SWEPCo's commitment.

In August 2007, hearings began before the APSC seeking pre-approval of the plant. The APSC staff recommended the application be approved and intervenors requested the motion be denied. In October 2007, final briefs and closing arguments were completed by all parties during which the APSC staff and Attorney General supported the plant. A decision by the APSC will occur within 60 days from October 22, 2007. In September 2007, the PUCT staff recommended that SWEPCo's application be denied suggesting the construction of the Turk Plant would adversely impact the development of competition in the SPP zone. The PUCT hearings were held in October 2007. The LPSC held hearings in September 2007 and during this proceeding, the LPSC staff expressed support for the project. If SWEPCo is not authorized to build the Turk plant, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred costs, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

Electric Transmission Texas LLC Joint Venture (Utility Operations segment)

In January 2007, we signed a participation agreement with MidAmerican Energy Holdings Company (MidAmerican) to form a joint venture company, Electric Transmission Texas, LLC (ETT), to fund, own and operate electric transmission assets in ERCOT. ETT filed with the PUCT in January 2007 requesting regulatory approval to operate as an electric transmission utility in Texas, to transfer from TCC to ETT approximately $76 million of transmission assets under construction and to establish a wholesale transmission tariff for ETT. ETT also requested PUCT approval of initial rates based on an 11.25% return on equity. A hearing was held in July 2007. On October 31, 2007, the PUCT issued an order approving the transaction and initial rates based on 9.96% return on equity. ETT and MidAmerican are reviewing the order.

In February 2007, TCC also made a regulatory filing at the FERC regarding the transfer of certain transmission assets from TCC to ETT. In April 2007, the FERC authorized the transfer. In July 2007, ETT made a subsequent filing requesting that FERC disclaim jurisdiction over ETT. In October 2007, FERC disclaimed jurisdiction over ETT.

AEP Utilities, Inc., a subsidiary of AEP, and MEHC Texas Transco LLC, a subsidiary of MidAmerican, each would hold a 50 percent equity ownership in ETT. ETT would not be consolidated with AEP for financial or tax reporting purposes.

AEP and MidAmerican plan for ETT to invest in additional transmission projects in ERCOT. Upon formation, the joint venture partners anticipate investments in excess of $1 billion of joint investment in Texas ERCOT transmission projects that could be constructed by ETT during the next several years.

In February 2007, ETT filed a proposal with the PUCT that addresses the Competitive Renewable Energy Zone (CREZ) initiative of the Texas Legislature, which outlines opportunities for additional significant investment in transmission assets in Texas. A CREZ hearing was held in June 2007 and the PUCT issued an interim order in August 2007. In that order, the PUCT directed ERCOT to perform studies by April 2008 that determine the necessary transmission upgrades to accommodate between 10,000 and 22,800 MW of wind development from CREZs across the Texas panhandle and central West Texas. The PUCT also indicated in its interim order that it plans to select transmission construction designees in the first quarter of 2008.

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

Potomac-Appalachian Transmission Highline (PATH) (Utility Operations segment)

On June 22, 2007, PJM's Board authorized the construction of a major new transmission line to address the reliability and efficiency needs of the PJM system. PJM has identified a need for a new line as early as 2012. The line would be 765kV for most of its length and would run approximately 290 miles from AEP's Amos substation in West Virginia to Allegheny Energy Inc.'s (AYE) proposed Kemptown station in north central Maryland (the Amos-to-Kemptown Line). The Amos-to-Kemptown Line has been named the "Potomac-Appalachian Transmission Highline" (PATH) by AEP and AYE.

Effective September 1, 2007, AEP and AYE formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH LLC) and its subsidiaries. The subsidiaries of PATH LLC will operate as transmission utilities owning certain electric transmission assets within PJM including the PATH project. The Amos-to-Kemptown Line has two segments: a segment running from AEP's Amos substation in West Virginia east to AYE's Bedington substation in West Virginia (the "West Virginia Facilities"), to be constructed and owned by PATH West Virginia Transmission Company, LLC, and a segment running east from the Bedington substation to AYE's Kemptown substation in Maryland (the "Bedington-Kemptown Facilities"), to be constructed and owned by PATH Allegheny Transmission Company, LLC.

In addition to the Amos-to-Kemptown Line, the joint venture will also pursue a high voltage transmission line up to 70 miles in length in northeastern Ohio (the "Ohio Facilities") extending to the Pennsylvania border. The Ohio Facilities would be constructed and owned by PATH Ohio Transmission Company, LLC, if the project is authorized by PJM prior to 2011. This project is currently under study in PJM's Regional Transmission Expansion Plan process.

The ownership in the West Virginia Facilities and the Ohio Facilities will be shared 50/50 between AEP and AYE. The Bedington-Kemptown Facilities will be owned solely by AYE. The ownership and management of the Ohio Facilities will be shared 50/50 between AEP and AYE.

Both AEP and AYE will be providing services to the PATH companies through service agreements. AEP will have lead responsibility for engineering, designing and managing construction of the 765-kV elements of the project, and AEP will provide business services to the PATH companies during the construction phase of the project. Both companies will provide siting, right-of-way and regulatory services to the PATH companies.

PATH LLC, on behalf of the PATH operating companies, plans to file for necessary approvals from FERC for the Amos-to-Kemptown Line in the fourth quarter of 2007. The PATH operating companies will seek regulatory approvals for the Amos-to-Kemptown project from the state utility commissions following completion of a routing study that is expected to occur in 2008.

The total cost of the Amos-to-Kemptown Line is estimated to be approximately $1.8 billion and AEP's estimated share will be approximately $600 million. The PATH companies will not be consolidated with AEP for financial or tax reporting purposes.

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 regulatory proceedings and our pending litigation see Note 4 – Rate Matters, Note 6 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2006 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees 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 are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

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

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. We are also monitoring possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change. All of these matters are discussed in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2006 Annual Report.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging 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. In April 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding.

In October 2007, we announced that we had entered into a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, we agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. In addition to completing the installation of previously announced environmental retrofit projects at many of the plants, we agreed to install selective catalytic reduction (SCR) and flue gas desulfurization (FGD or scrubbers) emissions control equipment on the Rockport Plant units.

Since 2004, we spent nearly $2.6 billion on installation of emissions control equipment on our coal-fueled plants in Kentucky, Ohio, Virginia and West Virginia as part of a larger plan to invest more than $5.1 billion by 2010 to reduce the emissions of our generating fleet.

Under the consent decree, we will pay a $15 million civil penalty and provide $36 million for environmental projects coordinated with the federal government and $24 million to the states for environmental mitigation. We recognized these amounts in the third quarter of 2007. See "Federal EPA Complaint and Notice of Violation" section of Note 4.

Litigation against three jointly-owned plants, operated by Duke Energy Ohio, Inc. and Dayton Power and Light Company, continues. We are unable to predict the outcome of these cases. We believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates or 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 and cash flows.

Clean Water Act Regulations

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

The rule was challenged in the courts by states, advocacy organizations and industry. In January 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. We cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. We may seek further review or relief from the schedules included in our permits.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2006 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

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. We adopted FIN 48 effective January 1, 2007. The effect of this interpretation on our financial statements was an unfavorable adjustment to retained earnings of $17 million. See "FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48"" section of Note 2 and Note 8 – Income Taxes.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural 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.

Our Generation and Marketing segment holds power sale contracts with commercial and industrial customers and wholesale power trading and marketing contracts within ERCOT.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, natural gas, coal, and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk management staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President – AEP Utilities, Chief Financial Officer, Senior Vice President of Commercial Operations and Treasurer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

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 adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. We support the work of the CCRO and embrace the disclosure standards applicable to our business activities. The following tables provide information on our risk management activities.

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

The following two tables summarize the various mark-to-market (MTM) positions included on our condensed consolidated balance sheet as of September 30, 2007 and the reasons for changes in our total MTM value included on our condensed consolidated balance sheet as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
September 30, 2007
(in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management	PLUS: MTM of Cash Flow	Total

				Contracts	and Fair Value Hedges	
Current Assets	$ 233	$ 47	$ 62	$ 342	$ 9	$ 351
Noncurrent Assets	199	63	79	341	6	347
Total Assets	432	110	141	683	15	698
Current Liabilities	(148)	(53)	(64)	(265)	(2)	(267)
Noncurrent Liabilities	(101)	(21)	(85)	(207)	(3)	(210)
Total Liabilities	(249)	(74)	(149)	(472)	(5)	(477)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 183	$ 36	$ (8)	$ 211	$ 10	$ 221

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2007
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	$ 236	$ 2	$ (5)	$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(50)	(1)	(2)	(53)
Fair Value of New Contracts at Inception When Entered During the Period (a)	6	49	-	55
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	2	-	-	2
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	7	(14)	(1)	(8)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(18)	-	-	(18)
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2007	$ 183	$ 36	$ (8)	211
Net Cash Flow and Fair Value Hedge Contracts				10
Total MTM Risk Management Contract Net Assets at September 30, 2007				$ 221

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

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

The following table presents:

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of September 30, 2007
(in millions)

	Remainder 2007	2008	2009	2010	2011	After 2011 (c)	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 5	$ (15)	$ 3	$ -	$ -	$ -	$ (7)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	29	66	40	31	-	-	166
Prices Based on Models and Other Valuation Methods (b)	1	(1)	6	5	7	6	24
Total	35	50	49	36	7	6	183
Generation and Marketing:							
Prices Actively Quoted – Exchange Traded Contracts	(3)	2	1	-	-	-	-
Prices Provided by Other External Sources – OTC Broker Quotes (a)	-	(6)	3	-	-	-	(3)
Prices Based on Models and Other Valuation Methods (b)	-	(3)	(2)	8	7	29	39
Total	(3)	(7)	2	8	7	29	36

All Other:							
Prices Actively Quoted – Exchange Traded Contracts	-	-	-	-	-	-	-
Prices Provided by Other External Sources – OTC Broker Quotes (a)	-	(2)	-	-	-	-	(2)
Prices Based on Models and Other Valuation Methods (b)	-	-	(4)	(4)	2	-	(6)
Total	-	(2)	(4)	(4)	2	-	(8)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	2	(13)	4	-	-	-	(7)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	29	58	43	31	-	-	161
Prices Based on Models and Other Valuation Methods (b)	1	(4)	-	9	16	35	57
Total	$ 32	$ 41	$ 47	$ 40	$ 16	$ 35	$ 211

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

(b) Prices Based on Models and Other Valuation Methods is used in the absence of independent 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 including values determinable by other third party transactions.

(c) There is mark-to-market value of $35 million in individual periods beyond 2011. $14 million of this mark-to-market value is in 2012, $8 million is in 2013, $7 million is in 2014, $2 million is in 2015, $2 million is in 2016 and $2 million is in 2017.

The determination of the point at which a market is no longer supported by independent quotes and therefore considered in the modeled category in the preceding table varies by market. The following table generally 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, 2007

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	27
	Physical Forwards	AEP East - Cinergy	39
	Physical Forwards	AEP - PJM West	39
	Physical Forwards	AEP - Dayton (PJM)	39
	Physical Forwards	AEP - ERCOT	27
	Physical Forwards	AEP - Entergy	15
	Physical Forwards	West Coast	39
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	39
Coal	Physical Forwards	PRB, NYMEX, CSX	39

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

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

We use foreign currency derivatives to lock in prices on certain transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedge strategies. 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 changes in cash flow hedges from December 31, 2006 to September 30, 2007. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Nine Months Ended September 30, 2007
(in millions)

	Power	Interest Rate and Foreign Currency	Total
	$ 17	$ (23)	$ (6)

Beginning Balance in AOCI, December 31, 2006			
Changes in Fair Value	4	(2)	2
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(15)	2	(13)
Ending Balance in AOCI, September 30, 2007	$ 6	$ (23)	$ (17)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 4	$ (2)	$ 2

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity meets our internal credit rating criteria will we extend unsecured credit. We use Moody's Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. We use our analysis, in conjunction with the rating agencies' information, to determine appropriate risk parameters. We also require cash deposits, letters of credit and parent/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, 2007, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 4.6%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of September 30, 2007, 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% of Net Exposure	Net Exposure of Counterparties >10%
Investment Grade	$ 649	$ 60	$ 589	-	$ -
Split Rating	25	11	14	2	13
Noninvestment Grade	24	3	21	2	19
No External Ratings:					
Internal Investment Grade	68	-	68	1	39
Internal Noninvestment Grade	13	2	11	3	8
Total as of September 30, 2007	$ 779	$ 76	$ 703	8	$ 79
Total as of December 31, 2006	$ 998	$ 161	$ 837	9	$ 169

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2009. This table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of September 30, 2007

	Remainder 2007	2008	2009
Estimated Plant Output Hedged	95%	88%	91%

<u>VaR Associated with Risk Management Contracts</u>

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, 2007, 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, 2007 (in millions)				Twelve Months Ended December 31, 2006 (in millions)			
End	High	Average	Low	End	High	Average	Low
$1	$6	$2	$1	$3	$10	$3	$1

Interest Rate Risk

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $925 million at September 30, 2007 and $870 million at December 31, 2006. 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 INCOME
For the Three and Nine Months Ended September 30, 2007 and 2006
(in millions, except per-share amounts and shares outstanding)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Utility Operations	$ 3,423	$ 3,478	$ 9,127	$ 9,259
Other	366	116	977	379
TOTAL	3,789	3,594	10,104	9,638
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,099	1,113	2,853	2,962
Purchased Energy for Resale	358	271	895	674
Other Operation and Maintenance	964	898	2,783	2,615
Gain on Disposition of Assets, Net	(2)	-	(28)	(68)
Asset Impairments and Other Related Charges	-	209	-	209
Depreciation and Amortization	381	382	1,144	1,084
Taxes Other Than Income Taxes	191	186	565	567
TOTAL	2,991	3,059	8,212	8,043
OPERATING INCOME	798	535	1,892	1,595
Interest and Investment Income	8	22	39	41
Carrying Costs Income	14	3	38	66
Allowance For Equity Funds Used During Construction	9	12	23	25
Gain on Disposition of Equity Investments, Net	-	-	-	3
INTEREST AND OTHER CHARGES				
Interest Expense	216	174	615	518
Preferred Stock Dividend Requirements of Subsidiaries	1	1	2	2
TOTAL	217	175	617	520
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	612	397	1,375	1,210
Income Tax Expense	205	133	443	394
Minority Interest Expense	1	1	3	2
Equity Earnings of Unconsolidated Subsidiaries	1	2	6	1
	407	265	935	815

INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS				
DISCONTINUED OPERATIONS, NET OF TAX	-	-	2	6
INCOME BEFORE EXTRAORDINARY LOSS	407	265	937	821
EXTRAORDINARY LOSS, NET OF TAX	-	-	(79)	-
NET INCOME	$ 407	$ 265	$ 858	$ 821
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	399,222,569	393,913,463	398,412,473	393,763,946
BASIC EARNINGS PER SHARE				
Income Before Discontinued Operations and Extraordinary Loss	$ 1.02	$ 0.67	$ 2.35	$ 2.07
Discontinued Operations, Net of Tax	-	-	-	0.01
Income Before Extraordinary Loss	1.02	0.67	2.35	2.08
Extraordinary Loss, Net of Tax	-	-	(0.20)	-
TOTAL BASIC EARNINGS PER SHARE	$ 1.02	$ 0.67	$ 2.15	$ 2.08
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	400,215,911	396,266,250	399,552,630	395,783,241
DILUTED EARNINGS PER SHARE				
Income Before Discontinued Operations and Extraordinary Loss	$ 1.02	$ 0.67	$ 2.34	$ 2.06
Discontinued Operations, Net of Tax	-	-	0.01	0.01
Income Before Extraordinary Loss	1.02	0.67	2.35	2.07
Extraordinary Loss, Net of Tax	-	-	(0.20)	-
TOTAL DILUTED EARNINGS PER SHARE	$ 1.02	$ 0.67	$ 2.15	$ 2.07
CASH DIVIDENDS PAID PER SHARE	$ 0.39	$ 0.37	$ 1.17	$ 1.11

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in millions)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 196	$ 301
Other Temporary Investments	231	425
Accounts Receivable:		
Customers	780	676
Accrued Unbilled Revenues	376	350
Miscellaneous	87	44
Allowance for Uncollectible Accounts	(41)	(30)
Total Accounts Receivable	1,202	1,040
Fuel, Materials and Supplies	961	913
Risk Management Assets	351	680
Regulatory Asset for Under-Recovered Fuel Costs	23	38
Margin Deposits	61	120
Prepayments and Other	86	71
TOTAL	3,111	3,588
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	19,749	16,787
Transmission	7,354	7,018
Distribution	11,894	11,338
Other (including coal mining and nuclear fuel)	3,363	3,405
Construction Work in Progress	2,809	3,473
Total	45,169	42,021
Accumulated Depreciation and Amortization	16,139	15,240
TOTAL - NET	29,030	26,781
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,365	2,477
Securitized Transition Assets	2,115	2,158
Spent Nuclear Fuel and Decommissioning Trusts	1,315	1,248
Goodwill	76	76
Long-term Risk Management Assets	347	378
Employee Benefits and Pension Assets	293	327
Deferred Charges and Other	804	910
TOTAL	7,315	7,574
Assets Held for Sale	-	44
TOTAL ASSETS	$ 39,456	$ 37,987

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, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,121	$ 1,360
Short-term Debt	587	18
Long-term Debt Due Within One Year	910	1,269
Risk Management Liabilities	267	541
Customer Deposits	326	339
Accrued Taxes	616	781
Accrued Interest	246	186
Other	835	962
TOTAL	4,908	5,456
NONCURRENT LIABILITIES		
Long-term Debt	13,866	12,429
Long-term Risk Management Liabilities	210	260
Deferred Income Taxes	4,585	4,690
Regulatory Liabilities and Deferred Investment Tax Credits	2,886	2,910
Asset Retirement Obligations	1,059	1,023
Employee Benefits and Pension Obligations	855	823
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	141	148
Deferred Credits and Other	976	775
TOTAL	24,578	23,058
TOTAL LIABILITIES	29,486	28,514
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		
2007 / 2006		
Shares Authorized 600,000,000 / 600,000,000		
Shares Issued 421,328,600 / 418,174,728		
(21,499,992 shares were held in treasury at September 30, 2007 and December 31, 2006)	2,739	2,718
Paid-in Capital	4,328	4,221
Retained Earnings	3,070	2,696
Accumulated Other Comprehensive Income (Loss)	(228)	(223)
TOTAL	9,909	9,412
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 39,456	$ 37,987

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, 2007 and 2006
(in millions)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 858	$ 821
Less: Discontinued Operations, Net of Tax	(2)	(6)
Income Before Discontinued Operations	856	815
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,144	1,084
Deferred Income Taxes	44	(88)
Deferred Investment Tax Credits	(18)	(20)
Extraordinary Loss, Net of Tax	79	-
Asset Impairments, Investment Value Losses and Other Related Charges	-	209
Carrying Costs Income	(38)	(66)
Mark-to-Market of Risk Management Contracts	22	(21)
Amortization of Nuclear Fuel	48	38
Deferred Property Taxes	118	105
Fuel Over/Under-Recovery, Net	(133)	158
Gain on Sales of Assets and Equity Investments, Net	(28)	(71)
Change in Other Noncurrent Assets	(87)	36
Change in Other Noncurrent Liabilities	116	26
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(209)	139
Fuel, Materials and Supplies	(13)	(84)
Margin Deposits	59	130
Accounts Payable	(54)	(49)
Customer Deposits	(13)	(235)
Accrued Taxes, Net	(119)	176
Accrued Interest	22	10
Other Current Assets	(33)	12
Other Current Liabilities	(133)	(108)
Net Cash Flows From Operating Activities	1,630	2,196
INVESTING ACTIVITIES		
Construction Expenditures	(2,595)	(2,428)
Change in Other Temporary Cash Investments, Net	(50)	20
Purchases of Investment Securities	(8,632)	(8,153)
Sales of Investment Securities	8,849	8,056
Acquisitions of Darby, Lawrenceburg and Dresden Plants	(512)	-
Proceeds from Sales of Assets	78	120
Other	(73)	(72)
Net Cash Flows Used For Investing Activities	(2,935)	(2,457)
FINANCING ACTIVITIES		
Issuance of Common Stock	116	24

Issuance of Long-term Debt		1,924		1,229
Change in Short-term Debt, Net		569		11
Retirement of Long-term Debt		(870)		(711)
Dividends Paid on Common Stock		(467)		(437)
Other		(72)		3
Net Cash Flows From Financing Activities		1,200		119
Net Decrease in Cash and Cash Equivalents		(105)		(142)
Cash and Cash Equivalents at Beginning of Period		301		401
Cash and Cash Equivalents at End of Period	$	196	$	259
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	549	$	462
Net Cash Paid for Income Taxes		363		206
Noncash Acquisitions Under Capital Leases		59		66
Construction Expenditures Included in Accounts Payable at September 30,		265		334
Nuclear Fuel Expenditures Included in Accounts Payable at September 30,		1		-
Noncash Assumption of Liabilities Related to Acquisitions		8		-

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, 2007 and 2006
(in millions)
(Unaudited)

	Common Stock				
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 9,412
FIN 48 Adoption, Net of Tax				(17)		(17)
Issuance of Common Stock	3	21	95			116
Common Stock Dividends				(467)		(467)
Other			12			12
TOTAL						9,056
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $6					(11)	(11)
Securities Available for Sale, Net of Tax of $3					(5)	(5)
SFAS 158 Costs Established as a Regulatory Asset for the Reapplication of SFAS 71, Net of Tax of $6					11	11
NET INCOME				858		858
TOTAL COMPREHENSIVE INCOME						853

SEPTEMBER 30, 2007	421	$	2,739	$	4,328	$	3,070	$	(228)	$	9,909

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, 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 SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual 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 or nine months ended September 30, 2007 are not necessarily indicative of results that may be expected for the year ending December 31, 2007. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2006 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2006 as filed with the SEC on February 28, 2007.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For the Utility Operations segment, normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and most nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Gains and losses are recorded for any retirements in the MEMCO Operations and Generation and Marketing segments. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

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

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

Revenue Recognition

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. We recognize the revenues on our Condensed Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory, and we purchase power back from the same RTO to supply power to our load. These power sales and purchases are reported on a net basis as revenues on our Condensed Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as an exchange.

Physical energy purchases, including those from all RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Energy for Resale on our Condensed Consolidated Statements of Income.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase-and-sale contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

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

Energy Marketing and Risk Management Activities

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

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

Management Assets or Liabilities as appropriate.

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

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the Condensed Consolidated Balance Sheets in the common shareholders' equity section. The following table provides the components that constitute the balance sheet amount in AOCI:

Components	September 30, 2007	December 31, 2006
	(in millions)	
Securities Available for Sale, Net of Tax	$ 13	$ 18
Cash Flow Hedges, Net of Tax	(17)	(6)
SFAS 158 Costs, Net of Tax	(224)	(235)
Total	$ (228)	$ (223)

At September 30, 2007, during the next twelve months, we expect to reclassify approximately $2 million of net gains from cash flow hedges in AOCI to Net Income at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from AOCI to Net Income can differ as a result of market fluctuations.

At September 30, 2007, thirty-three 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.

Earnings Per Share (EPS)

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

	Three Months Ended September 30,			
	2007		2006	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to Common Stock	$ 407		$ 265	
Average Number of Basic Shares Outstanding	399.2	$ 1.02	393.9	$ 0.67
Average Dilutive Effect of:				
Performance Share Units	0.5	-	2.0	-

Stock Options	0.3		-	0.2		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	0.1		-
Average Number of Diluted Shares Outstanding	400.2	$	1.02	396.3	$	0.67

	Nine Months Ended September 30, 2007			2006		
	(in millions, except per share data)					
			$/share			$/share
Earnings Applicable to Common Stock	$ 858			$ 821		
Average Number of Basic Shares Outstanding	398.4	$	2.15	393.8	$	2.08
Average Dilutive Effect of:						
Performance Share Units	0.6		-	1.6		(0.01)
Stock Options	0.4		-	0.2		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	0.1		-
Average Number of Diluted Shares Outstanding	399.6	$	2.15	395.8	$	2.07

The assumed conversion of our share-based compensation does not affect net earnings for purposes of calculating diluted earnings per share as of September 30, 2007.

Options to purchase 0.1 million and 0.4 million shares of common stock were outstanding at September 30, 2007 and 2006, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares for the period and, therefore, the effect would not be dilutive.

Supplementary Information

Related Party Transactions	**Three Months Ended September 30, 2007**	**2006**	**Nine Months Ended September 30, 2007**	**2006**
	(in millions)		**(in millions)**	
AEP Consolidated Purchased Energy:				
Ohio Valley Electric Corporation (43.47% Owned)	$ 59	$ 54	$ 164	$ 167
Sweeny Cogeneration Limited Partnership (a)	27	30	86	92
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)	7	8	24	23
AEP Consolidated Revenues – Utility Operations:				
Power Pool Purchases – Ohio Valley Electric Corporation	(12)	-	(16)	-

(43.47% Owned)

(a) In October 2007, we sold our 50% ownership in the Sweeny Cogeneration Limited Partnership. See “Sweeny Cogeneration Plant” section of Note 5.

Reclassifications

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

On our 2006 Condensed Consolidated Statement of Income, we reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. These reclassifications totaled $6 million and $19 million for the three and nine months ended September 30, 2006, respectively.

In our segment information, we reclassified two subsidiary companies, AEP Texas Commercial & Industrial Retail GP, LLC and AEP Texas Commercial & Industrial Retail LP, from the Utility Operations segment to the Generation and Marketing segment. Combined revenues for these companies totaled $7 million and $23 million for the three and nine months ended September 30, 2006, respectively. As a result, on our 2006 Condensed Consolidated Statement of Income, we reclassified these revenues from Utility Operations to Other.

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

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

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 2007 and standards issued but not implemented that we have determined relate to our operations.

SFAS 157 “Fair Value Measurements” (SFAS 157)

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

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts. We are evaluating the effect of the adoption of SFAS 157 on our results of operations and financial condition. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. Although we have not completed our analysis, we expect this cumulative effect adjustment will have an immaterial impact on our financial statements. We will adopt SFAS 157 effective January 1, 2008.

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

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

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. If we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS 159 effective January 1, 2008. Although we have not completed our analysis, we expect the adoption of this standard to have an immaterial impact on our financial statements.

EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

EITF 06-11 will be applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years beginning after September 15, 2007. We expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt EITF 06-11 effective January 1, 2008.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48" (FIN 48)

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." 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. We adopted FIN 48 effective January 1, 2007, with an unfavorable adjustment to retained earnings of $17 million.

FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

FIN 39-1 is effective for fiscal years beginning after November 15, 2007. We expect this standard to change our method of netting certain balance sheet amounts but are unable to quantify the effect. It requires retrospective application as a change in accounting principle for all periods presented. We will adopt FIN 39-1 effective January 1, 2008.

Future Accounting Changes

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

EXTRAORDINARY ITEM

In April 2007, Virginia passed legislation to reestablish regulation for retail generation and supply of electricity. As a result, we recorded an extraordinary loss of $118 million ($79 million, net of tax) during the second quarter of 2007 for the reestablishment of regulatory assets and liabilities related to our Virginia retail generation and supply operations. In 2000, we discontinued SFAS 71 regulatory accounting in our Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation. See "Virginia Restructuring" section of Note 3.

3. RATE MATTERS

As discussed in our 2006 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2006 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, cash flows and possibly financial condition. The following discusses ratemaking developments in 2007 and updates the 2006 Annual Report.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans

Ending December 31, 2008, the approved three-year RSPs provide CSPCo and OPCo increases in their generation rates by 3% and 7%, respectively, effective January 1 each year and allow possible additional annual generation rate increases of up to an average of 4% per year to recover governmentally-mandated costs. In January 2007, CSPCo and OPCo filed with the PUCO pursuant to the average 4% generation rate provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover new governmentally-mandated costs. CSPCo and OPCo implemented these proposed increases in May 2007 subject to refund. In October 2007, the PUCO issued an order in the average 4% proceeding which granted CSPCo and OPCo an annual generation rate increase through December 2008 of $19 million and $4 million, respectively. In September 2007, CSPCo and OPCo recorded a provision for refund to adjust revenues consistent with the rate revenues granted by the PUCO. Management expects that the average 4% rider will be reduced to implement the required refunds, while OPCo would implement a credit to customers' bills. CSPCo and OPCo intend to seek rehearing of the PUCO decision.

In October 2007, CSPCo and OPCo made a new filing with the PUCO pursuant to the average 4% generation rate provision of their RSPs for an additional increase in their annual generation rates effective January 2008 of $35 million and $12 million, respectively, to recover governmentally-mandated costs and increased costs related to marginal-loss pricing. CSPCo and OPCo will implement these proposed increases in January 2008 subject to refund until the PUCO issues a final order in the matter. Management is unable to predict the outcome of this filing and its impact on future results of operations and cash flows.

In March 2007, CSPCo filed an application under the average 4% generation rate provision of their RSP to adjust the Power Acquisition Rider (PAR) related to CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio. The PAR was increased to recover the cost of a new purchase power market contract to serve the load for that service territory. The PUCO approved the requested increase in the PAR, which is expected to increase CSPCo's revenues by $22 million and $38 million for 2007 and 2008, respectively.

In March 2007, CSPCo and OPCo filed a settlement agreement at the PUCO resolving the Ohio Supreme Court's remand of the PUCO’s RSP order. The settling parties agreed to have CSPCo and OPCo take bids for Renewable Energy Certificates (RECs). CSPCo and OPCo will give customers the option to pay a generation rate premium that would encourage the development of renewable energy sources by reimbursing CSPCo and OPCo for the cost of the RECs and the administrative costs of the program. The Office of Consumers’ Counsel, the Ohio Partners for Affordable Energy, the Ohio Energy Group and the PUCO staff supported this settlement agreement. In May 2007, the PUCO adopted the settlement agreement in its entirety.

Customer Choice Deferrals

CSPCo’s and OPCo’s restructuring settlement agreement approved by the PUCO in 2000, allows CSPCo and OPCo to establish regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general base rate filing which changes distribution rates. Through September 30, 2007, CSPCo and OPCo incurred $53 million and $54 million, respectively, of such costs and established regulatory assets of $27 million each for the future recovery of such costs. CSPCo and OPCo also have the right to recover $6 million and $7 million, respectively, of equity carrying costs in addition to these regulatory assets. In 2007, CSPCo and OPCo incurred $3 million and $4 million, respectively, of such costs and established regulatory assets of $2 million each for such costs. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure to recover such costs would have an adverse effect on results of operations and cash flows.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the average 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo 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 a period of no more than twelve months effective July 1, 2006. Through September 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. As of September 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered.

The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs collected for pre-construction costs, associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Ohio Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio Supreme Court heard oral arguments for these appeals in October 2007. Management believes that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase 1 cost-related recoveries.

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant have escalated to $2.2 billion. CSPCo and OPCo may need to request an extension to the 5-year start of construction requirement if the commencement of construction is delayed beyond 2011.

Distribution Reliability Plan

In the fourth quarter of 2006, as directed by the PUCO, CSPCo and OPCo filed a proposed enhanced reliability plan. The plan contemplated CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen-month period beginning July 2007.

In April 2007, CSPCo and OPCo filed a joint motion with the PUCO staff, the Ohio Consumers' Counsel, the Appalachian People's Action Coalition, the Ohio Partners for Affordable Energy and the Ohio Manufacturers Association to withdraw the proposed enhanced reliability plan. The motion was granted in May 2007. CSPCo and OPCo do not intend to implement the enhanced reliability plan without recovery of any incremental costs.

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load in accordance with a settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties that was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH to be paid by Ormet for power and a PUCO-approved market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is insufficient, an increase in RSP generation rates under the additional average 4% generation rate provision of the RSPs.

In December 2006, CSPCo and OPCo submitted a market price of $47.69 per MWH for 2007, which was approved by the PUCO in June 2007. CSPCo and OPCo have each amortized $5 million of their Ohio Franchise Tax phase-out tax regulatory liability to income through September 30, 2007. If the PUCO approves a lower market price in 2008, it could have an adverse effect on future results of operations and cash flows. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo off-system sales margins.

Texas Rate Matters

TCC TEXAS RESTRUCTURING

Texas District Court Appeal Proceedings

TCC recovered its net recoverable stranded generation costs through a securitization financing and is refunding its net other true-up items through a CTC rate rider credit under 2006 PUCT orders. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. The significant items appealed by TCC are:

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

Municipal customers and other intervenors also appealed the PUCT true-up and related orders seeking to further reduce TCC's true-up recoveries. In March 2007, the Texas District Court judge hearing the appeal of the true-up order affirmed the PUCT's April 4, 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. However, the District Court did not rule that the carrying cost rate was inappropriate. If the District Court's ruling on the carrying cost rate is ultimately upheld on appeal and remanded to the PUCT for reconsideration, the PUCT could either confirm the existing weighted average carrying cost (WACC) rate or determine a new rate. If the PUCT reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

The District Court judge also determined the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. If upheld on appeal, this ruling could have a materially favorable effect on TCC's results of operations and cash flows.

TCC, the PUCT and intervenors appealed the District Court true-up order rulings to the Texas Court of Appeals. Management cannot predict the outcome of these true-up and related proceedings. If TCC ultimately succeeds in its appeals in both state and federal court, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, or if TCC has a tax normalization violation, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's 2006 true-up and securitization orders, the PUCT reduced TCC's stranded generation costs and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million of EDFIT associated with TCC's generation assets for a total reduction of $61 million. The reductions were ordered after the PUCT concluded such reductions would not represent a violation of the Internal Revenue Code normalization requirements.

TCC filed a request for a private letter ruling with the IRS in June 2005 regarding the permissibility under the IRS rules and regulations of the ADITC and EDFIT reduction proposed by the PUCT. The IRS issued its private letter ruling in May 2006, which stated the PUCT's proposed flow-through to customers of the present value of the ADITC and EDFIT benefits as a reduction of stranded costs would result in a normalization violation. To address the matter and avoid a possible normalization violation, the PUCT agreed to allow TCC to defer an amount of the CTC refund totaling $103 million ($61 million in present value of ADITC and EDFIT associated with TCC's generation assets plus $42 million of related carrying costs) pending resolution of the normalization issue. If it is ultimately determined that a refund to customers through the true-up process of the ADITC and EDFIT is not a normalization violation, then TCC will be required to refund the $103 million, plus additional carrying costs adversely affecting future cash flows. However, if an ADITC and EDFIT reduction is ultimately determined to cause a normalization violation, TCC anticipates the PUCT will permit TCC to retain the $61 million present value of ADITC and EDFIT plus carrying costs, favorably impacting future results of operations and cash flows.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of September 30, 2007, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are actually returned to ratepayers under a nonappealable order. In TCC's True-up Proceeding brief in the Texas Court of Appeals, the PUCT requested a remand of the tax normalization issue to consider additional evidence, including TCC's private letter ruling issued after close of hearings and a change in proposed IRS regulations the PUCT had relied upon in its initial determination. Management intends to continue its efforts to work with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel

TCC's deferred fuel over-recovery regulatory liability is a component of the other true-up items net regulatory liability refunded through the CTC rate rider credit. In 2002, TCC and TNC filed with the PUCT seeking to reconcile fuel costs and establish their final deferred fuel balances. In its final fuel reconciliation orders, the PUCT ordered substantial reductions in TCC's and TNC's recoverable fuel costs for, among other things, the reallocation of additional AEP System off-system sales margins to TCC and TNC under a FERC-approved tariff. As of September 30, 2007, TCC has refunded the over-recovered deferred fuel through the CTC rate rider credit. Both TCC and TNC appealed the PUCT's rulings regarding a number of issues in the fuel orders in state court and challenged the jurisdiction of the PUCT over the allocation of off-system sales margins in the federal court. Intervenors also appealed the PUCT's final fuel rulings in state court seeking to increase the various allowances.

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales reallocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. The Court of Appeals affirmed the District Court's decision in the TNC case. In April 2007, the PUCT petitioned the United States Supreme Court for a review of the Court of Appeals' order. In October 2007, the United States Supreme Court denied review of TNC's case. As a result, TNC recorded income of $9 million in the third quarter of 2007 by reversing the previously recorded provision resulting from the PUCT's ordered reallocation of off-system sales margins. Since it is probable the outcome in the TCC case, still before the U.S. Court of Appeals, will be the same as in the TNC case, TCC also recorded income of $16 million by reversing its provision in the third quarter of 2007. Based on the TNC case, TCC reduced its deferred fuel regulatory liability by $16 million in the third quarter of 2007.

The PUCT or another interested party may file a complaint at the FERC to address the allocation issue. Although management cannot predict if a complaint may be filed at the FERC, management believes the allocations used were in accordance with the then-existing FERC-approved SIA and additional off-system sales margins should not be retroactively reallocated to the AEP West companies including TCC and TNC.

TCC Excess Earnings

In 2005, the Texas Court of Appeals issued a decision finding that the PUCT's prior order from the unbundled cost of service case requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. In June 2007, the Texas Supreme Court declined review. From 2002 to 2005, TCC refunded $55 million of excess earnings under the overturned PUCT order, including interest. On remand, the PUCT must determine how to implement the Court of Appeals decision given that unauthorized refunds were made. TCC's stranded cost recovery, which is currently on appeal, may be affected by the remedy ordered as a result of the unauthorized refunds. In 2005, management reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset for the expected refund to be received from the REPs, and believes its accounting is correct. However, certain parties continue to take positions that, if adopted, could result in TCC being required to pay additional amounts of excess earnings or interest which would adversely affect future results of operations and cash flows. Management cannot predict the outcome of these matters.

TCC Oklaunion Refund

In 2005, TCC filed a special request with the PUCT allowing TCC to file its True-up Proceeding before it had completed the sale of its share of the Oklaunion power plant. TCC agreed to provide customers the net economic benefit related to its continued ownership of the Oklaunion power plant until the sale closed. TCC also agreed to reduce stranded costs in the event the Oklaunion power plant sales price increased. In June 2007, TCC filed with the PUCT reporting no change in the sales price and to include the net economic benefit from the operation of the Oklaunion power plant in the CTC credit rider. As of September 30, 2007, TCC has recorded a $4 million regulatory liability for the net economic benefit related to the operation of the Oklaunion power plant. Management is unable to predict the ultimate outcome of this filing. If the PUCT orders a refund greater than the $4 million recorded liability, it would have an adverse effect on future results of operations and cash flows.

OTHER TEXAS RATE MATTERS

TCC and TNC Energy Delivery Base Rate Filings

TCC and TNC each filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rates in Texas. TCC and TNC requested increases in annual base rates of $81 million and $25 million, respectively. Both requests included a return on common equity of 11.25% and a favorable impact from an expiration of the CSW merger savings rate credits (merger credits). In March 2007, various intervenors and the PUCT staff filed their recommendations with increases ranging from $8 million to $30 million for TCC. The recommended return on common equity ranged from 9.00% to 9.75%. In April 2007, TCC filed rebuttal testimony reducing its requested increase to $70 million including a reduced requested return on common equity of 10.75%. In May 2007, TNC reached a settlement agreement for a revenue increase of $14 million including an $8 million increase in base rates and a $6 million increase related to the impact of the expiration of the merger credits. TNC received a final order in May 2007 and began billing the increase in June 2007.

Beginning in June 2007, TCC implemented an interim base rate increase of $50 million, subject to refund, in accordance with Texas law. In addition, TCC's merger credits were terminated in June 2007, which effectively increased base rates by $20 million on an annual basis. In May 2007, an ALJ issued an interim order affirming the termination of the merger credits. In June 2007, the PUCT affirmed the ALJ ruling. In August 2007, an ALJ issued a proposal for decision. In October 2007, the PUCT affirmed the ALJ's proposal for decision. TCC recognized revenues consistent with the final order which established a $20 million base rate increase, a $7 million decrease in depreciation rates, a $20 million increase in revenues related to the expiration of TCC's merger credits and a return on common equity of 9.96%. TCC estimates the base rate annual impact of this final order will increase TCC's pretax income by $47 million.

SWEPCo Fuel Reconciliation – Texas

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations for the three-year reconciliation period ended December 31, 2005. SWEPCo sought, in the proceedings, to include under-recoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The PUCT staff and intervenor disallowances ranged from $10 million to $28 million. In June 2007, an ALJ issued a proposal for decision recommending a $17 million disallowance. Results of operations for the second quarter of 2007 were adversely affected by $25 million to reflect the ALJ's decision that apply to the reconciliation period and subsequent periods through 2007. In August 2007, the PUCT issued a final order affirming the ALJ report. In September 2007, SWEPCo filed a motion for rehearing. In October 2007, the PUCT granted SWEPCo's motion for rehearing. The PUCT reversed its prior determination that SO_2 allowance gains should be credited through the fuel clause. However, the PUCT ruled SWEPCo was obligated to credit the fuel clause with gains from sales of emissions allowances through June 30, 2006. This change affects allowances sold after June 2006 and its impact will be considered in the fourth quarter of 2007. In October 2007, the PUCT issued a revised order which should allow SWEPCo to reverse $7 million of its earlier provision in the fourth quarter of 2007. SWEPCO is considering whether to challenge other parts of the order.

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

Several parties including the Office of Public Utility Counsel and the cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's respective former affiliated REPs). In 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the amount of unaccounted-for energy (UFE) included in TNC's PTB fuel factor. The Court of Appeals upheld the District Court regarding the UFE issue. AEP's third quarter 2005 pretax earnings were adversely affected by $3 million at an assumed 1% UFE factor to reflect the impact of the court's decision. The Supreme Court of Texas has remanded this issue to the PUCT. If the PUCT adopts a different UFE factor on remand, future results of operations and cash flows would be adversely affected. Management is unable to predict the outcome of this remand or its impact on future results of operations and cash flows.

Stall Unit

See "Stall Unit" section within Louisiana Rate Matters for disclosure.

Turk Plant

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

Virginia Rate Matters

Virginia Restructuring

In April 2004, Virginia enacted legislation that amended the Virginia Electric Utility Restructuring Act extending the transition period to market rates for the generation and supply of electricity, including the extension of capped rates, through December 31, 2010. The legislation provided APCo with specified cost recovery opportunities during the extended capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain unrecovered incremental environmental and reliability costs incurred on and after July 1, 2004. Under the amended restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to have the opportunity to recover incremental E&R costs.

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation and supply rates. These amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation and supply will return to cost-based regulation in lieu of market-based rates. The legislation provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investments, (b) demand side management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments; significant return on equity enhancements for investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. The new re-regulation legislation should result in significant positive effects on APCo's future earnings and cash flows from the mandated enhanced future returns on equity, the reduction of regulatory lag from the opportunities to adjust base rates on a biennial basis and the new opportunities to request timely recovery of certain new costs not included in base rates.

With the new re-regulation legislation, APCo's generation business again met the criteria for application of regulatory accounting principles under SFAS 71. The extraordinary pretax reduction in APCo's earnings and shareholder's equity from reapplication of SFAS 71 regulatory accounting of $118 million ($79 million, net of tax) was recorded in the second quarter of 2007. This extraordinary net loss relates to the reestablishment of $139 million in net generation-related customer-provided removal costs as a regulatory liability, offset by the restoration of $21 million of deferred state income taxes as a regulatory asset. In addition, APCo established a regulatory asset of $17 million for qualifying SFAS 158 pension costs of the generation operations that, for ratemaking purposes, are deferred for future recovery under the new re-regulation legislation. AOCI and Deferred Income Taxes increased by $11 million and $6 million, respectively.

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 its active fuel clause. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which was estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. In May 2006, the Virginia SCC issued an order placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund.

In May 2007, the Virginia SCC issued a final order approving an overall annual base rate increase of $24 million effective as of October 2006 and approving a return on equity of 10.0%. As a result of the final order, APCo's second quarter pretax earnings decreased by approximately $3 million due to a decrease in revenues of $42 million net of a recorded provision for refund and related interest offset by (a) a $15 million net effect from the deferral of unrecovered incremental E&R costs incurred from October 1, 2006 through June 30, 2007 to be collected in a future E&R filing, (b) a $9 million net deferral of ARO costs to be recovered over 10 years and (c) a $15 million retroactive decrease in depreciation expense. As a result of the Virginia SCC decision to limit the recovery of incremental E&R costs through the new base rates, APCo will continue to defer for future recovery unrecovered incremental E&R costs incurred through 2008 utilizing the E&R surcharge mechanism. APCo completed the $127 million refund in August 2007.

Virginia E&R Costs Recovery Filing

In July 2007, APCo filed a request with the Virginia SCC seeking recovery over the twelve months beginning December 1, 2007 of approximately $60 million of unrecovered incremental E&R costs inclusive of carrying costs thereon incurred from October 1, 2005 through September 30, 2006. In August 2007, the Virginia SCC issued a scheduling order to begin the proceeding before a hearing examiner on November 5, 2007. In October 2007, the Virginia SCC staff and the Attorney General both filed testimony recommending that APCo recover $49 million of its $60 million of requested E&R costs. The two differences between APCo's request and the Virginia SCC staff and the Attorney General's recommendations relate to the recovery of carrying costs on the unrecovered incremental E&R costs and the appropriate return on equity rate. APCo intends to file in 2008 for recovery of additional incurred incremental E&R costs recorded and deferred after September 30, 2006.

APCo is currently recovering $21 million of incurred E&R costs through the initial E&R surcharge that will expire on November 30, 2007. Through September 30, 2007, APCo deferred $70 million in incremental E&R costs to be recovered in the current and future E&R filings. APCo has not recognized $15 million of equity carrying charges, which are recognizable when collected. The $70 million regulatory asset does not include carrying costs on the unrecovered incremental E&R costs and is based on a return on equity rate which approximates the Virginia SCC staff and Attorney General's recommendations. As a result, if APCo is awarded only $49 million for the E&R costs incurred for the twelve months ended September 30, 2006 as recommended by the Virginia SCC staff and the Attorney General, it will not have to reverse any of its regulatory asset deferrals.

Virginia Fuel Clause Filing

In July 2007, APCo filed an application with the Virginia SCC to seek an annualized increase, effective September 1, 2007, of $33 million for fuel costs and a sharing of the benefits of off-system sales between APCo and its customers. This filing was made in compliance with the minimum 25% retention of off-system sales margins provision of the new re-regulation legislation which is effective with the first fuel clause filing after July 1, 2007. This sharing requirement in the new law also includes a true-up to actual off-system sales margins. In addition, APCo requested authorization to defer for future recovery the difference between off-system sales margins credited to customers at 100% of the ordered amount through the current base rate margin rider and 75% of actual off-system sales margins as provided in the new law from July 1, 2007 until the new fuel rate becomes effective.

In August 2007, the Virginia SCC issued a scheduling order that implemented APCo's proposed termination of its base rate off-system sales margin rider on an interim basis, subject to refund, on September 1, 2007. The order also implemented APCo's proposed new fuel factor on an interim basis, effective September 1, 2007, which includes a credit for the sharing of 75% of off-system sales margins with customers in compliance with the new law. In October 2007, APCo, the Virginia SCC staff and certain intervenors filed memorandums addressing legal issues identified by the Virginia SCC regarding the appropriateness of the timing of the implementation of the new expanded fuel factor and off-system sales margins sharing with customers. Hearings are scheduled for November 2007. In October 2007, the Virginia SCC staff submitted testimony stating off-system sales margin sharing for July and August 2007 should be denied. In addition, the Virginia SCC staff asserted that no language exists in the statute requiring implementation of off-system sales margin sharing any earlier than 2011. Future results of operations and cash flows could be adversely affected if the Virginia SCC delays the effective date of the new expanded fuel clause beyond APCo's filed request.

West Virginia IGCC Plant

In July 2007, APCo filed a request with the Virginia SCC to recover, over the twelve months beginning January 1, 2009, a return on projected construction work in progress including development, design and planning costs from July 1, 2007 through December 31, 2009 estimated to be $45 million associated with the proposed 629 MW IGCC plant to be constructed in West Virginia for an estimated cost of $2.2 billion. APCo is requesting authorization to defer a return on actual pre-construction costs incurred beginning July 1, 2007 until such costs are recovered, starting January

1, 2009 in accordance with the new re-regulation legislation. The new re-regulation legislation provides for full recovery of all costs plus return on equity incentives for such new capacity once the plant is placed in service. See "West Virginia IGCC Plant" section within West Virginia Rate Matters.

West Virginia Rate Matters

APCo and WPCo Expanded Net Energy Cost (ENEC) Filing

In April 2007, the WVPSC issued an order establishing an investigation and hearing concerning APCo's and WPCo's 2007 ENEC compliance filing. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits and other energy/transmission items. In the March 2007 ENEC joint filing, APCo and WPCo filed for an increase of approximately $101 million including a $72 million increase in ENEC and a $29 million increase in construction cost surcharges to become effective July 1, 2007. In June 2007, the WVPSC issued an order approving, without modification, a joint stipulation and agreement for settlement reached among the parties. The settlement agreement provided for an increase in annual non-base revenues of approximately $86 million effective July 1, 2007. This annual revenue increase primarily includes $55 million of ENEC and $29 million of construction cost surcharges. The ENEC portion of the increase is subject to a true-up, which should avoid an earnings affect from an under-recovery of ENEC costs if they exceed the $55 million.

West Virginia IGCC Plant

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity (CCN) to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, WV.

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both the ongoing finance costs of the project during the construction period as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. If APCo receives all necessary approvals, the plant could be completed as early as mid-2012 and currently is expected to cost an estimated $2.2 billion. In July 2007, the WVPSC staff and intervenors filed to delay the procedural schedule by 90 days. APCo supported the changes to the procedural schedule. The statutory decision deadline was revised to March 2008. In July 2007, the WVPSC approved the revised procedural schedule. Through September 30, 2007, APCo deferred pre-construction IGCC costs totaling $11 million. If the plant is not built and these costs are not recoverable, future results of operations and cash flows would be adversely affected.

Indiana Rate Matters

Indiana Depreciation Study Filing

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counsel (OUCC) that would provide direct benefits to I&M's customers if new lower book depreciation rates were approved by the IURC. The direct benefits would include a $5 million credit to fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement were to be approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended and parties to the settlement agreed to a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately $69 million 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. In June 2007, the IURC approved the settlement agreement, but modified the effective date of the new book depreciation rates to the date I&M filed a general rate petition. On June 19, 2007, I&M and the OUCC notified the IURC that the parties would accept the modification to the settlement agreement. Therefore, I&M filed its rate petition and reduced its book depreciation rates as agreed upon in the settlement agreement.

The settlement agreement modification reduced book depreciation rates, which will result in an increase of $37 million in pretax earnings for the period June 19, 2007 to December 31, 2007. The $37 million increase is partially offset by a $5 million regulatory liability, recorded in June 2007, to provide for the agreed-upon fuel credit. I&M's approved book depreciation rates are subject to further review in the general rate case. Management expects new base rates will become effective in early 2009.

Indiana Rate Filing

In June 2007, I&M filed a rate notification petition with the IURC regarding its intent to file for a base rate increase with a proposed test year ended September 30, 2007. The petition indicated, among other things, the filing would include a request to implement rate tracker mechanisms for certain variable components of the cost of service including PJM RTO costs, reliability enhancement costs, demand side management/energy efficiency program costs, off-system sales margins, and net environmental compliance costs. This filing will also reflect the revenue requirement reduction associated with an annual reduction in book depreciation expense. In August 2007, the IURC approved the September 30, 2007 test year and the inclusion of the above trackers in the rate filing with a rate case to be filed no later than January 31, 2008. Management expects to file the case in early 2008 with a decision expected in early 2009.

Indiana Rate Cap

Effective July 1, 2007, I&M's rate cap ended for both base and fuel rates in Indiana. As a result, I&M's fuel factor in Indiana increased with the July 2007 billing month to recover the projected cost of fuel. I&M will resume deferring through revenues any under/over-recovered fuel costs for future recovery/refund. Under the capped rates, I&M was unable to recover $44 million of fuel costs since 2004 of which $7 million adversely impacted 2007 pretax earnings through June 30, 2007. Future results of operations should no longer be adversely impacted by fuel costs.

Michigan Rate Matters

Michigan Depreciation Study Filing

In December 2006, I&M filed a depreciation study in Michigan seeking to reduce its book depreciation rates. In September 2007, the Michigan Public Service Commission (MPSC) approved a settlement agreement authorizing I&M to implement new book depreciation rates. Based on the depreciation study included in the settlement, I&M agreed to decrease pretax annual depreciation expense, on a Michigan jurisdictional basis, by approximately $10 million. This settlement reflects 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 retail customers' electric service rates. In addition and as a result of the new MPSC-approved rates, I&M will decrease pretax annual depreciation expense, on a FERC jurisdictional basis, by approximately $11 million which will reduce wholesale rates for customers representing half the load beginning in November 2007 and reduce wholesale rates for the remaining customers in June 2008.

Kentucky Rate Matters

Environmental Surcharge Filing

In July 2006, KPCo filed for approval of an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge. KPCo estimates the amended environmental compliance plan and revised tariff would increase revenues over 2006 levels by approximately $2 million in 2007 and $6 million in 2008 for a total of $8 million of additional revenue at current cost projections. In January 2007, the KPSC issued an order approving KPCo's proposed plan and surcharge. Future recovery is based upon actual environmental costs and is subject to periodic review and approval by the KPSC.

In November 2006, the Kentucky Attorney General (AG) and the Kentucky Industrial Utility Consumers (KIUC) filed an appeal with the Kentucky Court of Appeals of the Franklin Circuit Court's 2006 order upholding the KPSC's 2005 Environmental Surcharge order specifically as it relates to the recovery of affiliated AEP Power Pool costs. In KPCo's order, the KPSC approved recovery of its environmental costs at its Big Sandy Plant and its share of environmental costs incurred as a result of the AEP Power Pool capacity settlement. The KPSC has allowed KPCo to recover these FERC-approved allocated AEP Power Pool costs, via the environmental surcharge, since the KPSC's first environmental surcharge order in 1997. KPCo presently recovers $7 million a year in environmental surcharge revenues.

In March 2007, the KPSC issued an order, at the request of the Kentucky Attorney General, stating the environmental surcharge collections authorized in the January 2007 order that are associated with out-of-state generating facilities and paid through the AEP Power Pool should be collected over the six months beginning March 2007, subject to refund, pending the outcome of the Court of Appeals process. At this time, management is unable to predict the outcome of this proceeding and its effect on KPCo's current environmental surcharge revenues or on the January 2007 KPSC order increasing KPCo's environmental rates. If the appeal is successful, future results of operations and cash flows could be adversely affected.

Validity of Nonstatutory Surcharges

In August 2007, the Franklin Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The ruling results from the AG's appeal of the KPSC's approval of a natural gas distribution surcharge for replacement of gas mains. The AG notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. The KPSC and Duke Energy are appealing the Franklin County Circuit Court decision.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could appeal an existing surcharge KPCo is collecting to the Franklin County Circuit Court. KPCo's fuel clause, annual Rockport Plant capacity surcharge, merger surcredit and credit system sales rider are not specifically authorized by statute. These surcharges are currently producing net annual revenues of approximately $10 million. KPCo's Environmental and demand side management surcharges are specifically authorized by statute. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG's filed brief took the position that the KPCo fuel clause should be invalidated because the KPSC lacked the authority by statute to implement a fuel clause for KPCo without a full rate case review. In August 2007, the KPSC issued an order stating despite the Franklin County Circuit Court decision, the KPSC has the authority to provide for surcharges and surcredits at least until a Court of Appeals ruling. The appeals process could take up to two years to complete. In August 2007, the AG agreed to stipulate to a stay order over the Franklin County Circuit Court's decision pending the appeal decision. KPCo's exposure is indeterminable at this time. If the appeal is unfavorable, future results of operations and cash flows could be adversely affected.

<u>Oklahoma Rate Matters</u>

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 purchased power costs through its fuel clause resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. The Oklahoma Industrial Energy Customers (OIEC) filed a motion asking the OCC to reconsider its order on the jurisdictional issue. The OCC stayed its final order regarding the FERC jurisdictional issue. In October 2007, the OCC lifted its stay stating the OCC does not have jurisdiction regarding the allocation methodology for off-system sales margins.

The OIEC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins to 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. However, to date, there has been no claim asserted at the FERC that the AEP System deviated from the FERC-approved allocation methodologies, but even if one were asserted, management believes that its allocation of off-system sales margins under the FERC-approved SIA agreement was consistent with that agreement. In October 2007, the OCC directed OCC Staff to file a complaint at FERC concerning this matter.

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 PSO failed to achieve that he alleges existed during the year. In August 2007, an ALJ issued a report recommending that PSO's fuel procurement practices were prudent and no adjustments were warranted. No parties appealed the recommendation. In October 2007, the OCC issued a final order adopting the ALJ's report.

In February 2006, the OCC enacted a rule, 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 periodic reviews. PSO filed its testimony in June 2007 covering the year 2005. The OCC Staff and intervenors filed testimony in September 2007.

In May 2007, PSO submitted a filing to the OCC to adjust its fuel/purchase power rates. In the filing, PSO netted the $42 million of under-recovered pre-2002 reallocated purchased power costs against their $48 million over-recovered fuel balance as of April 30, 2007. The $6 million net over-recovered fuel/purchased power cost deferral balance will be refunded over the twelve-month period beginning June 2007. However, in August 2007, the OIEC filed a motion asking the OCC to order a refund of the $42 million pre-2002 reallocated purchased power costs netted against the current over-recovered fuel balance. In October 2007, the OCC denied the OIEC's request for refund of the $42 million of under-recovered pre-2002 reallocated purchased power costs.

Management cannot predict the outcome of the pending fuel and purchased power costs and prudence reviews, or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred.

Oklahoma Rate Filing

In November 2006, PSO filed a request to increase base rates by $50 million for Oklahoma jurisdictional customers and set return on equity at 11.75% with a proposed effective date in the second quarter of 2007. PSO also proposed a formula rate plan that, if approved as filed, would permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve months beginning six months after the test year. The proposed formula rate plan would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and prevent the capitalization of a significant amount of AFUDC that would have been recorded during the construction period and recovered in the future through depreciation expense.

The ALJ issued a report in May 2007 recommending a 10.5% return on equity but did not compute an overall revenue requirement. The ALJ's report did not recommend adopting a formula rate plan, but did recommend recovery through a rider of certain generation and transmission projects' financing costs during construction. However, the report also contained an alternative recommendation that the OCC could delay a decision on the rider and take up this issue in PSO's application seeking regulatory approval of a new coal-fueled generating unit. PSO implemented interim rates, subject to refund, for residential customers beginning July 2007.

In October 2007, the OCC issued a final order providing for a $10 million annual increase in base rates with a return on equity of 10%. The final order also provides for lower depreciation rates, which PSO estimates will decrease depreciation expense by approximately $10 million on an annual basis. PSO estimates the annual impact of this final order will increase PSO's pretax income by $20 million. The final order also requires PSO to file a plan with the OCC to promote energy efficiency and conservation programs within 60 days. PSO implemented the approved rates in October 2007.

Lawton and Peaking Generation Settlement Agreement

In November 2003, pursuant to an application by Lawton Cogeneration, L.L.C. (Lawton) seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court (the Court). In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Court issued a decision in June 2005, affirming portions of the OCC's order and remanding certain provisions. The Court affirmed the OCC's finding that Lawton established a legally-enforceable obligation and ruled that it was within the OCC's discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO's avoided energy cost. Hearings were held on the remanded issues in April and May 2006.

In April 2007, all parties in the case filed a settlement agreement with the OCC resolving all issues. The OCC approved the settlement agreement in April 2007. The OCC staff, the Attorney General, the Oklahoma Industrial Energy Consumers and Lawton Cogeneration, L.L.C. supported this settlement agreement. The settlement agreement provides for a purchase fee of $35 million to be paid by PSO to Lawton and for Lawton to provide, at PSO's direction, all rights to the Lawton Cogeneration Facility including permits, options and engineering studies. PSO paid the $35 million purchase fee in June 2007 and recorded the purchase fee as a regulatory asset and will recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service, currently expected to be 2008. PSO expects these units will have a substantially lower plant-in-service cost than the proposed Lawton Cogeneration Facility. PSO may request approval from the OCC for recovery of costs exceeding the cost cap if special circumstances occur necessitating a higher level of costs. Such costs will continue to be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. Under the settlement, PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units.

Red Rock Generating Facility

In July 2006, PSO announced plans to enter into an agreement with Oklahoma Gas and Electric (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit at the site of OG&E's existing Sooner Plant near Red Rock, in north central Oklahoma. PSO would own 50% of the new unit, OG&E would own approximately 42% and the Oklahoma Municipal Power Authority (OMPA) would own approximately 8%. OG&E would manage construction of the plant. OG&E and PSO requested pre-approval to construct the Red Rock Generating Facility and implement a recovery rider. In March 2007, the OCC consolidated PSO's pre-approval application with OG&E's request. The Red Rock Generating Facility was estimated to cost $1.8 billion and was expected to be in service in 2012. The OCC staff and the ALJ recommended the OCC approve PSO's and OG&E's filing. As of September 2007, PSO incurred approximately $20 million of pre-construction costs and contract cancellation fees.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but denied PSO's and OG&E's application for construction pre-approval stating PSO and OG&E failed to fully study other alternatives. Since PSO and OG&E could not obtain pre-approval to build the Red Rock Generating Facility, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. Management believes the pre-construction costs capitalized, including any cancellation fees, were prudently incurred, as evidenced by the OCC staff and the ALJ's recommendations that the OCC approve PSO's filing, and established a regulatory asset for future recovery. Management believes such pre-construction costs are probable of recovery and intends to seek full recovery of such costs in the near future. If recovery is denied, future results of operations and cash flows would be adversely affected. As a result of the OCC's decision, PSO will consider various alternative options to meet its capacity needs in the future.

2007 Oklahoma Ice Storm

In October 2007, PSO filed with the OCC requesting recovery of $13 million of operation and maintenance expenses related to service restoration effort after a January 2007 ice storm. PSO proposed to establish a regulatory asset of $13 million and to amortize this asset coincident with the gains from the sale of SO_2 allowances made during 2007 and thereafter until such gains provide for the full recovery of the regulatory asset. If the OCC adopts the PSO proposal, it would have a favorable impact on future results of operations and cash flows.

<u>Louisiana Rate Matters</u>

Louisiana Compliance Filing

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

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdictional customers, based on a proposed 10% return on equity. The recommended reduction range was subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo filed rebuttal testimony in January 2007. Constructive settlement negotiations are making meaningful progress. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely affect future results of operations, cash flows and possibly financial condition.

Stall Unit

In May 2006, SWEPCo announced plans to build a new intermediate load 480 MW natural gas-fired combustion turbine combined cycle generating unit at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings with the PUCT and the Arkansas Public Service Commission (APSC) during the third quarter of 2006 and the LPSC during the first quarter of 2007 to seek approvals to construct the unit. The Stall Unit is estimated to cost $375 million, excluding AFUDC, and expected to be in service in mid-2010. As of September 2007, SWEPCo incurred and capitalized approximately $15 million and has contractual commitments of an additional $17 million. If the Stall Unit is not approved, cancellation fees may be required to terminate SWEPCo's commitment.

In March 2007, the PUCT approved SWEPCo's request. In Louisiana, this request has been separated from the original request, which included the Turk Plant. Neither the LPSC nor the APSC have set a procedural schedule for the project. The project is contingent upon obtaining pre-approval from the APSC, the LPSC, the PUCT and the Louisiana Department of Environmental Quality. If SWEPCo is not authorized to build the Stall Unit, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred costs, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

Turk Plant

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

<u>**Arkansas Rate Matters**</u>

Turk Plant

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named Turk Plant. SWEPCo submitted filings with the APSC in December 2006 and the PUCT and LPSC in February 2007 to seek approvals to proceed with the plant. In September 2007, OMPA signed a joint ownership agreement and agreed to own approximately 7% of the Turk Plant. SWEPCo continues discussions with Arkansas Electric Cooperative Corporation and North Texas Electric Cooperative to become potential partners in the Turk Plant. SWEPCo anticipates owning approximately 73% of the Turk Plant and will operate the facility. The Turk Plant is estimated to cost $1.3 billion in total with SWEPCo's portion estimated to cost $950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in mid-2011. As of September 2007, SWEPCo incurred and capitalized approximately $206 million and has contractual commitments for an additional $875 million. If the Turk Plant is not approved, cancellation fees may be required to terminate SWEPCo's commitment.

In August 2007, hearings began before the APSC seeking pre-approval of the plant. The APSC staff recommended the application be approved and intervenors requested the motion be denied. In October 2007, final briefs and closing arguments were completed by all parties during which the APSC staff and Attorney General supported the plant. A decision by the APSC will occur within 60 days from October 22, 2007. In September 2007, the PUCT staff recommended that SWEPCo's application be denied suggesting the construction of the Turk Plant would adversely impact the development of competition in the SPP zone. The PUCT hearings were held in October 2007. The LPSC held hearings in September 2007 and during this proceeding, the LPSC staff expressed support for the project. If SWEPCo is not authorized to build the Turk plant, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred costs, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

Stall Unit

See “Stall Unit” section within Louisiana Rate Matters for disclosure.

FERC Rate Matters

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP and other transmission owners in the region covered by PJM and the Midwest ISO (MISO) eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. Approximately $10 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of the AEP East companies’ SECA customers. The AEP East companies reached settlements with certain SECA customers related to approximately $69 million of such revenues for a net refund of $3 million. The AEP East companies are in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and will consume about $7 million of the reserves for refunds, leaving approximately $115 million of contested SECA revenues and $30 million of refund reserves. If the ALJ’s initial decision were upheld in its entirety, it would disallow approximately $90 million of the AEP East companies’ remaining $115 million of unsettled gross SECA revenues. Based on recent settlement experience and the expectation that most of the $115 million of unsettled SECA revenues will be settled, management believes that the remaining reserve of $30 million will be adequate to cover all remaining settlements.

In September 2006, AEP, together with Exelon Corporation and The Dayton Power and Light Company, filed an extensive post-hearing brief and reply brief noting exceptions to the ALJ’s initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ’s findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining $115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ’s decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations, cash flows and financial condition.

The FERC PJM Regional Transmission Rate Proceeding

In January 2005, certain transmission owners in PJM proposed continuation of the zonal rate design in PJM after the June 2005 FERC deadline. With the elimination of T&O rates and the expiration of SECA rates, zonal rates would provide the AEP System no revenue for use of its transmission facilities by other parties in PJM and the MISO. AEP protested the zonal rate proposal and at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate the AEP East companies 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 proposed and supported a new PJM rate regime generally referred to as a Highway/Byway 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 the Highway/Byway proposed rates to be just and reasonable alternatives. The ALJ also found FERC staff's proposed Postage Stamp rate to be just and reasonable and recommended that 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.

In April 2007, the FERC issued an order reversing the ALJ's decision. The FERC ruled that the current PJM rate design is just and reasonable for existing transmission facilities. However, the FERC ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. As a result of this order, the AEP East companies' retail customers will bear the full cost of the existing AEP east transmission zone facilities. Presently AEP is collecting the full cost of those facilities from its retail customers with the exception of Indiana and Michigan customers. As a result of this order, the AEP East companies' customers will also be charged a share of the cost of future new 500 kV and higher voltage transmission facilities built in PJM, most of which are expected to be upgrades of the facilities in other zones of PJM. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them as a result of this order, if upheld. AEP has requested rehearing of this order. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new east transmission facilities, results of operations, cash flows and financial condition. In May 2007, the AEP East companies filed for rehearing related to this FERC decision.

Since the FERC's decision in 2005 to cease through-and-out rates and replace them temporarily with SECA rates, which ceased on April 1, 2006, the AEP East companies increased their retail rates in all states except Indiana, Michigan and Tennessee to recover lost T&O and SECA revenues. The AEP East companies presently recover from retail customers approximately 85% of the lost T&O/SECA transmission revenues of $128 million a year. Future results of operations, cash flows and financial condition will continue to be adversely affected in Indiana, Michigan and Tennessee until these lost T&O/SECA transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, voted to continue zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore a regional rate design change is required to recognize the provision and use of transmission service in the Super Region since it is not sufficiently uniform between transmission owners and users to justify zonal rates. Management is unable to predict the outcome of this case.

SPP Transmission Formula Rate Filing

In June 2007, AEPSC filed revised tariff sheets on behalf of PSO and SWEPCo for the AEP pricing zone of the SPP OATT. The revised tariff sheets seek to establish an up-to-date revenue requirement for SPP transmission services over the facilities owned by PSO and SWEPCo and implement a transmission cost of service formula rate.

PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. The primary impact of the filed revised tariff will be an increase in network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP pricing zone of SPP. If the proposed formula rate and requested return on equity are approved, the 2008 network transmission service revenues from nonaffiliates will increase by approximately $10 million compared to the revenues that would result from the presently approved network transmission rate. PSO and SWEPCo take service under the same rate, and will also incur the increased OATT charges resulting from the filing, but will receive corresponding revenue to offset the increase. In August 2007, the FERC issued an order conditionally accepting PSO's and SWEPCo's proposed formula rate, subject to a compliance filing, suspended the effective date until February 1, 2008 and established hearing and settlement judge proceedings. In October 2007, AEPSC submitted a compliance filing on behalf of PSO and SWEPCo. Multiple intervenors have protested or requested re-hearing of the order. Discovery and settlement discussions have begun.

PJM Marginal-Loss Pricing

On June 1, 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads. Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through September 30, 2007, AEP experienced an increase in the cost of delivering energy from the generating plant locations to customer load zones partially offset by cost recoveries and increased off-system sales resulting in a net loss of approximately $25 million. AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue through the appropriate stakeholder processes a modification of such methodology. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and is seeking recovery in current and future fuel or base rate filings as appropriate in each of its eastern zone states. In the interim, these costs will have an adverse effect on future results of operations and cash flows. Management is unable to predict whether full recovery will ultimately be approved.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2006 Annual Report should be read in conjunction with this report.

GUARANTEES

There are certain immaterial liabilities recorded for guarantees. 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, 2007, the maximum future payments for all the LOCs were approximately $69 million with maturities ranging from November 2007 to October 2008.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of September 30, 2007, SWEPCo has collected approximately $33 million through a rider for final mine closure costs, of which approximately $15 million is recorded in Deferred Credits and Other and approximately $18 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sales agreements is discussed in the 2006 Annual Report, “Dispositions” section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.3 billion (approximately $1 billion relates to the Bank of America (BOA) litigation, see “Enron Bankruptcy” section of this note). There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $59 million ($39 million, net of tax) as of September 30, 2007.

Railcar Lease

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years; (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value; or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. Assuming the fair market value of the equipment is zero at the end of the current lease term, the maximum potential loss was approximately $30 million ($20 million, net of tax) as of September 30, 2007. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at our generating units over a 20-year period. In April 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding.

On October 9, 2007, we announced that we had entered into a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, we agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. In addition to completing the installation of previously announced environmental retrofit projects at many of the plants, including the installation of flue gas desulfurization (FGD or scrubbers) equipment at Big Sandy and at Muskingum River plants by the end of 2015, we agreed to install selective catalytic reduction (SCR) and FGD emissions control equipment at Rockport Plant. Unit 1 at the Rockport Plant will be retrofit by the end of 2017, and Unit 2 will be retrofit by the end of 2019. We also agreed to install selective non-catalytic reduction, a NO_x-reduction technology, by the end of 2009 at Clinch River Plant.

Since 2004, we spent nearly $2.6 billion on installation of emissions control equipment on our coal-fueled plants in Kentucky, Ohio, Virginia and West Virginia as part of a larger plan to invest more than $5.1 billion by 2010 to reduce the emissions of our generating fleet.

We agreed to operate SCRs year round during 2008 at Mountaineer, Muskingum River and Amos plants, and agreed to plant-specific SO_2 emission limits for Clinch River and Kammer plants.

Under the consent decree, we will pay a $15 million civil penalty and provide $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation. We expensed these amounts in the third quarter of 2007.

The consent decree will resolve all issues related to various parties' claims against us in the two pending NSR cases. The consent decree has been filed with the U.S. District Court. The consent decree is subject to a 30-day public comment period and final approval by the Court. A hearing on the motion to approve the consent decree is scheduled for December 10, 2007.

We believe we can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If we are unable to recover such costs, it would adversely affect our future results of operations, cash flows and possibly financial condition.

Cases are still pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer, and Stuart stations. No trial date has yet been established in the Stuart case, but the units, operated by Dayton Power and Light Company, are equipped with SCR controls and the installation of FGD controls will be completed in 2007. The Beckjord and Zimmer case is scheduled for a liability trial in May 2008. Zimmer is equipped with both FGD and SCR controls. Beckjord and Zimmer are operated by Duke Energy Ohio, Inc. 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.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, we might have for civil penalties under the pending CAA proceedings for our jointly-owned plants. 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 market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect our future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled to commence during the first quarter of 2008.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately \$228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation limiting 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 and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007 removing the heat input references from the Welsh permit and clarifying the sulfur content of fuels burned at the plant is limited to 0.5% on an as-received basis. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion.

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

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. We believe the actions are without merit and intend to defend against the claims.

TEM Litigation

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

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

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

In May 2007, the United States Court of Appeals for the Second Circuit ruled that the lower court was correct in finding that TEM breached the PPA and we did not breach the PPA. It also ruled that the lower court applied an incorrect standard in denying us any damages for TEM's breach of the 20-year term of the PPA holding that we are entitled to the benefit of our bargain and that the trial court must determine our damages. The Court of Appeals vacated approximately $117 million of our $123 million judgment for damages against TEM related to replacement products and remanded the issue for further proceedings to determine the correct amount of those damages. One part of the judgment is final, that involves TEM's liability for damages applicable to gas peaking and post-actual commercial operation date products. We expect TEM to pay the amount of those damages, approximately $8 million, including interest, in the fourth quarter of 2007.

Enron Bankruptcy

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

After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. In 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage facility. In 2003, the Texas state court granted partial summary judgment in favor of the BOA

Syndicate. In August 2006, the Court of Appeals for the First District of Texas vacated the trial court's judgment and dismissed the BOA Syndicate's case. The BOA Syndicate did not seek review of this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL's motion to have the case assigned to the judge who heard the case originally was granted. HPL intends to defend against any renewed claims by BOA.

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage facility to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel facility and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. In April 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. The case in federal court in Texas was set for trial beginning April 2007 but the Court continued the trial pending a decision on the motions for summary judgment in the New York case.

In August 2007, the Judge in the New York action, issued a decision granting BOA summary judgment without awarding any damages and dismissing our claims. The Judge held another hearing in September 2007 and said that he plans a further hearing on the damages issue. We asked the Judge to certify an appeal of the legal issues decided by his summary judgment rulings prior to any ruling on damages. At this time we are unable to predict how the Judge will rule on the pending request. If the Judge issues a judgment directing us to pay an amount in excess of the gain on the sale of HPL, described below, and if we are unsuccessful in having the judgment reversed or modified, the judgment could have a material adverse effect on results of operations, cash flows, and possibly financial condition.

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 and recognition of the gain on the sale are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter. The deferred gain, estimated to be $382 million and $380 million at September 30, 2007 and December 31, 2006, respectively, is included in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

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

Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in Federal District Court, Columbus, Ohio. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2006, the plaintiffs filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. In August 2007, the appeals court reversed the trial court's decision and held that the plaintiff did have standing to pursue his claim. The appeals court remanded the case to the trial court to consider the issue of whether the plaintiff is an adequate representative for the class of plan participants on whose behalf the litigation would be pursued. We intend to continue to defend against these claims.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were filed in California. In addition, a number of other cases were filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases were transferred to the United States District Court for the District of Nevada but subsequently were remanded to California state court. In 2005 and subsequently, the judge in Nevada dismissed a number of the remaining cases on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. In July 2007, the judge in the California cases stayed those proceedings pending a decision by the Ninth Circuit in the federal cases. In September 2007, the United States Court of Appeals for the Ninth Circuit reversed the dismissal of two of the cases and remanded those cases to the trial court. However, the Ninth Circuit must rule on AEP's claim that the plaintiffs failed to timely appeal the trial judge's separate dismissal of AEP. In the other case, AEP has pending before the trial court a separate motion to dismiss based on plaintiffs' failure to state a claim against the AEP companies that was not addressed when the trial judge dismissed the case based on the filed rate doctrine. We will continue to defend each case where an AEP company is a defendant.

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 because the market for power was allegedly dysfunctional at the time such contracts were executed. An ALJ recommended rejection of the complaint, holding that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. On September 25, 2007, the U.S. Supreme Court decided to review the Ninth Circuit's decision. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

5. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

ACQUISITIONS

2007

Darby Electric Generating Station (Utility Operations segment)

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

Lawrenceburg Generating Station (Utility Operations segment)

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for $325 million and the assumption of liabilities of $3 million. AEGCo completed the purchase in May 2007. The Lawrenceburg plant is located in Lawrenceburg, Indiana, adjacent to I&M's Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW. AEGCo sells the power to CSPCo through a FERC-approved unit power contract.

Dresden Plant (Utility Operations segment)

In August 2007, AEGCo agreed to purchase the partially completed Dresden Plant from Dominion Resources, Inc. for $85 million and the assumption of liabilities of $2 million. AEGCo completed the purchase in September 2007. Management estimates that approximately $180 million in additional costs (excluding AFUDC) will be required to finish the construction of the plant. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. When completed in 2009, the Dresden Plant will have a generating capacity of 580 MW.

2006

None

DISPOSITIONS

2007

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for $42.8 million plus capital adjustments. The sale did not have an impact on our results of operations nor do we expect the remaining litigation to have a significant effect on our results of operations.

Intercontinental Exchange, Inc. (ICE) (All Other)

During March 2007, we sold 130,000 shares of ICE and recognized a $16 million pretax gain ($10 million, net of tax). We recorded the gains in Interest and Investment Income on our 2007 Condensed Consolidated Statement of Income. We recorded our remaining investment of approximately 138,000 shares in Other Temporary Investments on our Condensed Consolidated Balance Sheets.

Texas REPs (Utility Operations segment)

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. We received $20 million and $70 million payments in 2007 and 2006, respectively, for our share in earnings. These payments are reflected in Gain/Loss on Disposition of Assets, Net on our Condensed Consolidated Statements of Income. The payment we received in 2007 was the final payment under the earnings sharing agreement.

Sweeny Cogeneration Plant (Generation and Marketing segment)

In October 2007, we sold our 50% equity interest in the Sweeny Cogeneration Plant (Sweeny) to ConocoPhillips for approximately $80 million, including working capital and the buyer's assumption of project debt. The Sweeny Cogeneration Plant is a 450 MW cogeneration plant located within ConocoPhillips' Sweeny refinery complex southwest of Houston, Texas. We are the managing partner of the plant, which is co-owned by General Electric Company. As a result of the sale, we estimate that we will realize a $46 million pretax gain in the fourth quarter of 2007.

In addition to the sale of our interest in Sweeny, we agreed to separately sell our purchase power contract for our share of power generated by Sweeny through 2014 for $11 million to ConocoPhillips. ConocoPhillips also agreed to assume certain related third-party power obligations. These transactions were completed in conjunction with the sale of our 50% equity interest in October 2007. As a result of this sale, we estimate that we will realize an $11 million pretax gain in the fourth quarter of 2007. In the fourth quarter of 2007, we estimate that we will realize a total of $57 million in pretax gains related to the sales of our investments in the Sweeny Plant and the related purchase power contracts.

2006

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

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600 MW power plant in Mexico. In February 2006, we completed the sale of the 50% interest in Bajio for $29 million with no effect on our 2006 results of operations.

DISCONTINUED OPERATIONS

We determined that certain of our operations were discontinued operations and classified them as such for all periods presented. We recorded the following in 2007 and 2006 related to discontinued operations:

Nine Months Ended September 30,	U.K. Generation (a) (in millions)
2007 Revenue	$ -
2007 Pretax Income	3
2007 Earnings, Net of Tax	2
2006 Revenue	$ -
2006 Pretax Income	9
2006 Earnings, Net of Tax	6

(a) The 2007 amounts relate to tax adjustments from the sale. Amounts in 2006 relate to a release of accrued liabilities for the settlement of the London office lease and tax adjustments related to the sale.

For the quarter ended September 30, 2007 and 2006, there was no income statement impact related to our discontinued operations. 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, 2007 and 2006.

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville. We classified TCC's assets related to the Oklaunion Power Station in Assets Held for Sale on our Condensed Consolidated Balance Sheet at December 31, 2006. The plant did not meet the "component-of-an-entity" criteria because the plant did not have cash flows that can be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because the plant did not operate individually, but rather as a part of the AEP System.

Assets Held for Sale were as follows:

Texas Plants	September 30, 2007	December 31, 2006
	(in millions)	
Other Current Assets	$ -	$ 1
Property, Plant and Equipment, Net	-	43
Total Assets Held for Sale	$ -	$ 44

6. BENEFIT PLANS

We adopted SFAS 158 as of December 31, 2006. We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes are deferred for future recovery.

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the three and nine months ended September 30, 2007 and 2006:

	Pension Plans		Other Postretirement Benefit Plans	
Three Months Ended September 30, 2007 and 2006	2007	2006	2007	2006
		(in millions)		
Service Cost	$ 24	$ 23	$ 11	$ 10
Interest Cost	59	57	26	26
Expected Return on Plan Assets	(85)	(82)	(26)	(24)
Amortization of Transition Obligation	-	-	6	7
Amortization of Net Actuarial Loss	15	20	3	5
Net Periodic Benefit Cost	$ 13	$ 18	$ 20	$ 24

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
		(in millions)		

Nine Months Ended September 30, 2007 and 2006				
Service Cost	$ 72	$ 71	$ 32	$ 30
Interest Cost	176	171	78	76
Expected Return on Plan Assets	(254)	(248)	(78)	(70)
Amortization of Transition Obligation	-	-	20	21
Amortization of Net Actuarial Loss	44	59	9	15
Net Periodic Benefit Cost	$ 38	$ 53	$ 61	$ 72

7. BUSINESS SEGMENTS

As outlined in our 2006 Annual Report, our primary business strategy and the core of our business focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio continues to have commission-determined transition rates.

Our principal operating business segments and their related business activities are as follows:

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

MEMCO Operations
- Barging operations that annually transport approximately 34 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Approximately 35% of the barging operations relates to the transportation of coal, 30% relates to agricultural products, 18% relates to steel and 17% relates to other commodities.

Generation and Marketing
- IPPs, wind farms and marketing and risk management activities primarily in ERCOT. Our 50% interest in the Sweeny Cogeneration Plant was sold in October 2007. See "Sweeny Cogeneration Plant" section of Note 5.

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

- Parent's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in the fourth quarter of 2006.

The tables below present our reportable segment information for the three and nine months ended September 30, 2007 and 2006 and balance sheet information as of September 30, 2007 and December 31, 2006. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's segment presentation.

	Nonutility Operations				
Utility Operations	MEMCO Operations	Generation and	All Other (a)	Reconciling Adjustments	Consolidated

			Marketing (in millions)			
Three Months Ended September 30, 2007						
Revenues from:						
External Customers	$ 3,423	$ 134	$ 241	$ (9)	$ -	$ 3,789
Other Operating Segments	177	4	(161)	19	(39)	-
Total Revenues	$ 3,600	$ 138	$ 80	$ 10	$ (39)	$ 3,789
Net Income (Loss)	$ 388	$ 18	$ 3	$ (2)	$ -	$ 407

		Nonutility Operations				
	Utility Operations	**MEMCO Operations**	**Generation and Marketing**	**All Other (a)**	**Reconciling Adjustments**	**Consolidated**
			(in millions)			
Three Months Ended September 30, 2006						
Revenues from:						
External Customers	$ 3,478	$ 135	$ 14	$ (33)	$ -	$ 3,594
Other Operating Segments	(41)	4	-	52	(15)	-
Total Revenues	$ 3,437	$ 139	$ 14	$ 19	$ (15)	$ 3,594
Net Income (Loss)	$ 378	$ 19	$ 4	$ (136)	$ -	$ 265

		Nonutility Operations				
	Utility Operations	**MEMCO Operations**	**Generation and Marketing**	**All Other (a)**	**Reconciling Adjustments**	**Consolidated**
			(in millions)			
Nine Months Ended September 30, 2007						
Revenues from:						
External Customers	$ 9,127	$ 367	$ 574	$ 36	$ -	$ 10,104
Other Operating Segments	460	10	(347)	(14)	(109)	-
Total Revenues	$ 9,587	$ 377	$ 227	$ 22	$ (109)	$ 10,104
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 879	$ 40	$ 17	$ (1)	$ -	$ 935
Discontinued Operations, Net of Tax	-	-	-	2	-	2
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income	$ 800	$ 40	$ 17	$ 1	$ -	$ 858

Nonutility Operations

	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Nine Months Ended September 30, 2006						
Revenues from:						
External Customers	$ 9,259	$ 368	$ 47	$ (36)	$ -	$ 9,638
Other Operating Segments	(60)	9	-	89	(38)	-
Total Revenues	$ 9,199	$ 377	$ 47	$ 53	$ (38)	$ 9,638
Income (Loss) Before Discontinued Operations	$ 902	$ 54	$ 10	$ (151)	$ -	$ 815
Discontinued Operations, Net of Tax	-	-	-	6	-	6
Net Income (Loss)	$ 902	$ 54	$ 10	$ (145)	$ -	$ 821

		Nonutility Operations				
September 30, 2007	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 44,547	$ 255	$ 566	$ 38	$ (237)(b)	$ 45,169
Accumulated Depreciation and Amortization	15,978	58	105	7	(9)(b)	16,139
Total Property, Plant and Equipment – Net	$ 28,569	$ 197	$ 461	$ 31	$ (228)(b)	$ 29,030
Total Assets	$ 38,423	$ 326	$ 746	$ 11,948	$ (11,987) (c)	$ 39,456

		Nonutility Operations				
December 31, 2006	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 41,420	$ 239	$ 327	$ 35	$ -	$ 42,021
Accumulated Depreciation and Amortization	15,101	51	83	5	-	15,240
Total Property, Plant and Equipment – Net	$ 26,319	$ 188	$ 244	$ 30	$ -	$ 26,781
Total Assets	$ 36,632	$ 315	$ 342	$ 11,460	$ (10,762)(c)	$ 37,987
Assets Held for Sale	44	-	-	-	-	44

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in the fourth quarter of 2006.

(b) Reconciling Adjustments for Total Property, Plant and Equipment and Accumulated Depreciation and Amortization as of September 30, 2007 represent the elimination of an intercompany capital lease that began during the first quarter of 2007.

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

8. INCOME TAXES

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

Audit Status

We, along with our subsidiaries, file income tax returns in various state, local, and foreign jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2000. The IRS and other taxing authorities routinely examine our tax returns. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. We are currently under examination in several state and local jurisdictions. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations.

We have settled with the IRS on all issues from the audits of our consolidated federal income tax returns for years prior to 1997. We have effectively settled all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipate payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2005 are presently being audited by the IRS and we anticipate that the audit of the 2000 through 2003 years will be completed by the end of 2007.

The IRS has proposed certain adjustments to our foreign tax credit and interest allocation positions. Management has evaluated the proposed adjustments and has agreed to pay the related taxes. Management does not anticipate that the adjustments will result in a material change to our financial position.

FIN 48 Adoption

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recognized a $17 million increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

At January 1, 2007, the total amount of unrecognized tax benefits under FIN 48 was $175 million. We believe it is reasonably possible that there will be a $46 million net decrease in unrecognized tax benefits due to the settlement of audits and the expiration of statute of limitations within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $73 million. There are $66 million of tax positions for which the ultimate deductibility is highly certain but the timing of such deductibility is uncertain. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

Prior to the adoption of FIN 48, we recorded interest and penalty accruals related to income tax positions in tax accrual accounts. With the adoption of FIN 48, we began recognizing interest accruals related to income tax positions in interest income or expense as applicable, and penalties in Other Operation and Maintenance. As of January 1, 2007, we accrued $25 million for the payment of uncertain interest and penalties.

Michigan Tax Restructuring

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law is effective January 1, 2008 and replaces the Michigan Single Business Tax that is scheduled to expire at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198 which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis differences triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15-year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. We have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect our results of operations, cash flows or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	September 30, 2007	December 31, 2006
	(in millions)	
Senior Unsecured Notes	$ 9,752	$ 8,653
Pollution Control Bonds	2,134	1,950
First Mortgage Bonds	-	90
Defeased First Mortgage Bonds (a)	19	27
Notes Payable	303	337
Securitization Bonds	2,257	2,335
Notes Payable To Trust	113	113
Spent Nuclear Fuel Obligation (b)	257	247
Other Long-term Debt	2	2
Unamortized Discount (net)	(61)	(56)
Total Long-term Debt Outstanding	14,776	13,698
Less Portion Due Within One Year	910	1,269
Long-term Portion	$ 13,866	$ 12,429

(a) In May 2004, cash and treasury securities were deposited with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of $19 million at both September 30, 2007 and December 31, 2006. Trust Fund Assets related to this obligation of $22 million and $2 million at September 30, 2007 and December 31, 2006, respectively, are included in Other Temporary Investments and $21 million at December 31, 2006, is included in Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. In

December 2005, cash and treasury securities were deposited with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond was retired in June 2007. The defeased TNC First Mortgage Bond had a balance of $8 million at December 31, 2006. Trust fund assets related to this obligation of $9 million at December 31, 2006, are included in Other Temporary Investments on our Condensed Consolidated Balance Sheet. 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 related to this obligation of $280 million and $274 million at September 30, 2007 and December 31, 2006, respectively, are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2007 are shown in the tables below.

Company	Type of Debt		Principal Amount (in millions)	Interest Rate (%)	Due Date	
Issuances:						
APCo	Pollution Control Bonds	$	75	Variable	2037	
APCo	Senior Unsecured Notes		250	5.65	2012	
APCo	Senior Unsecured Notes		250	6.70	2037	
CSPCo	Pollution Control Bonds		45	Variable	2040	
OPCo	Pollution Control Bonds		65	4.90	2037	
OPCo	Senior Unsecured Notes		400	Variable	2010	
PSO	Pollution Control Bonds		13	4.45	2020	
SWEPCo	Senior Unsecured Notes		250	5.55	2017	
Non-Registrant:						
AEGCo	Senior Unsecured Notes		220	6.33	2037	(a)
KPCo	Senior Unsecured Notes		325	6.00	2017	
TCC	Pollution Control Bonds		6	4.45	2020	
TNC	Pollution Control Bonds		44	4.45	2020	
Total Issuances		$	1,943(b)			

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

(a) AEGCo's senior unsecured notes due 2037 are payable over the life of the notes as a $7.3 million annual principal amount plus accrued interest paid semiannually in March and September.

(b) Amount indicated on statement of cash flows of $1,924 million is net of issuance costs and unamortized premium or discount.

In May 2007, I&M remarketed its outstanding $50 million Pollution Control Bonds, resulting in a new interest rate of 4.625%. No proceeds were received related to this remarketing. The principal amount of the Pollution Control Bonds is reflected in Long-term Debt on our Condensed Consolidated Balance Sheet as of September 30, 2007.

In August 2007, TCC remarketed its outstanding $60 million Pollution Control Bonds, resulting in a new interest rate of 5.20%. No proceeds were received related to this remarketing. The principal amount of Pollution Control Bonds is reflected in Long-term Debt on our Condensed Consolidated Balance Sheet as of September 30, 2007.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date	
Retirements and Principal Payments:					
AEP	Senior Unsecured Notes	$ 345	4.709	2007	
APCo	Senior Unsecured Notes	125	Variable	2007	
OPCo	Notes Payable	3	6.81	2008	
OPCo	Notes Payable	6	6.27	2009	
PSO	Pollution Control Bonds	13	6.00	2020	
SWEPCo	First Mortgage Bonds	90	7.00	2007	
SWEPCo	Notes Payable	4	4.47	2011	
SWEPCo	Notes Payable	4	6.36	2007	
SWEPCo	Notes Payable	3	Variable	2008	
Non-Registrant:					
AEGCo	Senior Unsecured Notes	2	6.33	2037	(a)
AEP Subsidiaries	Notes Payable	10	Variable	2017	
CSW Energy, Inc.	Notes Payable	4	5.88	2011	
KPCo	Senior Unsecured Notes	125	5.50	2007	
TCC	Securitization Bonds	53	5.01	2008	
TCC	Securitization Bonds	25	4.98	2010	
TCC	Pollution Control Bonds	6	6.00	2020	
TNC	Pollution Control Bonds	44	6.00	2020	
TNC	Defeased First Mortgage Bonds	8	7.75	2007	
Total Retirements and Principal Payments		$ 870			

(a) AEGCo's Senior Unsecured Notes due 2037 are payable over the life of the notes as a $7.3 million annual principal amount plus accrued interest paid semiannually in March and September.

In October 2007, KPCo retired $48 million of 6.91% Senior Unsecured Notes due in 2007.

Short-term Debt

Short-term debt is used to fund our corporate borrowing program and fund other short-term cash needs. Our outstanding short-term debt was as follows:

	September 30, 2007			December 31, 2006	
Type of Debt	**Outstanding Amount (in millions)**	**Interest Rate**		**Outstanding Amount (in millions)**	**Interest Rate**
Commercial Paper – AEP	$ 559	5.60%	(a)	$ -	-
Commercial Paper – JMG (b)	2	5.3588%		1	5.56%
Line of Credit – Sabine (c)	26	6.07%		17	6.38%
Total	$ 587			$ 18	

(a) Weighted average rate.
(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce available liquidity under AEP's credit facilities.
(c) Sabine is consolidated under FIN 46. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

In March 2007, we amended the terms of our credit facilities. The amended facilities are structured as two $1.5 billion credit facilities, with an option in each to issue up to $300 million as letters of credit, expiring separately in March 2011 and April 2012.

Dividend Restrictions

Under the Federal Power Act, AEP's public utility subsidiaries are restricted from paying dividends out of stated capital.

Sale of Receivables – AEP Credit

In October 2007, we renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $650 million from a bank conduit to purchase receivables from AEP Credit. Under the agreement, the commitment will increase to $700 million for the months of August and September to accommodate seasonal demand. This agreement will expire in October 2008.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Net Income
(in millions)

Third Quarter of 2006		$ 31
Changes in Gross Margin:		
Retail Margins	13	
Off-system Sales	18	
Transmission Revenues, Net	(22)	
Other	(14)	
Total Change in Gross Margin		(5)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(27)	
Depreciation and Amortization	9	
Taxes Other Than Income Taxes	1	
Carrying Costs Income	36	
Other Income, Net	(8)	
Interest Expense	(18)	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		5
Third Quarter of 2007		$ 24

Net Income decreased $7 million to $24 million. The key drivers of the decrease were a $5 million decrease in Gross Margin and a $7 million increase in Operating Expenses and Other, partially offset by a $5 million decrease in Income Tax Expense.

The major components of the 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 $13 million due to the impact of the Virginia base rate order issued in May 2007, the Virginia E&R and fuel cost recovery filings and increased demand in the residential class associated with favorable weather conditions. Cooling degree days increased approximately 22%.
- Margins from Off-System sales increased $18 million primarily due to higher sales volumes and power prices in the east, benefits from AEP's eastern natural gas fleet, and higher trading margins.
- Transmission Revenues, Net decreased $22 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.
-

Other revenue decreased $14 million primarily due to the reversal in the third quarter of 2006 of previously deferred gains on sales of allowances associated with the Virginia Environmental and Reliability Costs (E&R) case.

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

- Other Operation and Maintenance expenses increased $27 million primarily due to the settlement agreement regarding alleged violations of the NSR provisions of the CAA, of which $26 million was allocated to APCo. See "Federal EPA Complaint and Notice of Violation" section of Note 4.
- Depreciation and Amortization expenses decreased $9 million primarily due to the write-off in the third quarter of 2006 of previously deferred depreciation expenses associated with the E&R case.
- Carrying Costs Income increased $36 million primarily due to the write-off in the third quarter of 2006 of previously recorded carrying costs income associated with the E&R case.
- Other Income, Net decreased $8 million primarily due to a $6 million decrease in the equity component of AFUDC resulting from AFUDC recorded in the third quarter of 2006 associated with the E&R case and a lower construction work in progress (CWIP) balance after the Wyoming-Jacksons Ferry 765 kV line and the Mountaineer scrubber were placed into service. In addition, interest income from the Utility Money Pool decreased $2 million.
- Interest Expense increased $18 million primarily due to a $9 million decrease in the debt component of AFUDC resulting from AFUDC recorded in the third quarter of 2006 associated with the E&R case. In addition, Interest Expense also increased due to a $2 million increase in interest expense from the Utility Money Pool and a $4 million increase in interest expense from long-term debt issuances.
- Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income and state income taxes partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

<u>Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006</u>

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007
Net Income Before Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2006		$ 114
Changes in Gross Margin:		
Retail Margins	9	
Off-system Sales	30	
Transmission Revenues, Net	(32)	
Other	(10)	
Total Change in Gross Margin		(3)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(35)	
Depreciation and Amortization	16	
Taxes Other Than Income Taxes	3	
Carrying Costs Income	36	
Other Income, Net	(13)	
Interest Expense	(33)	

Total Change in Operating Expenses and Other		(26)
Income Tax Expense		13
NNine Months Ended September 30, 2007	$	98

Net Income Before Extraordinary Loss decreased $16 million to $98 million in 2007. The key drivers of the decrease were a $26 million increase in Operating Expenses and Other, partially offset by a $13 million decrease in Income Tax Expense.

The major components of the 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 $9 million due to the impact of the Virginia base rate order issued in May 2007, the Virginia E&R and fuel cost recovery filings and increased demand in the residential class associated with favorable weather conditions. Cooling degree days increased approximately 33%.
- Margins for Off-system Sales increased $30 million primarily due to higher trading margins.
- Transmission Revenues, Net decreased $32 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.
- Other revenue decreased $10 million primarily due to lower gains on sales of allowances and the reversal in the third quarter of 2006 of previously deferred gains on sales of allowances associated with the E&R case.

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

- Other Operation and Maintenance expenses increased $35 million primarily due to the following:
  - A $26 million increase resulting from the settlement between AEP and the Federal EPA regarding alleged violations of the NSR provisions of the CAA. The $26 million represents APCo's allocation of the settlement. See "Federal EPA Complaint and Notice of Violation" section of Note 4.
  - A $9 million increase in steam maintenance expenses resulting from 2007 forced and planned outages at the Amos and Glen Lyn plants.
- Depreciation and Amortization expenses decreased $16 million primarily due to the following:
  - An $8 million decrease resulting from lower Virginia depreciation rates implemented retroactively to January 2006 partially offset by additional depreciation expense for the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006, and the Mountaineer scrubber, which was placed in service in February 2007.
  - A $10 million decrease resulting from a net deferral of $10 million in ARO costs as approved in APCo's Virginia base rate case.
  - A $9 million decrease in depreciation expense related to the write-off in the third quarter of 2006 of previously deferred depreciation expense associated with the E&R case.

  These decreases were partially offset by:
  - The amortization of carrying charges of $12 million that are being collected through E&R surcharges.
- Carrying Costs Income increased $36 million primarily due to the write-off in the third quarter of 2006 of previously recorded carrying costs income associated with the E&R case.
-

Other Income, Net decreased $13 million primarily due to lower interest income from the Utility Money Pool of $4 million. In addition, the equity component of AFUDC decreased $8 million resulting from AFUDC recorded in the third quarter of 2006 associated with the E&R case and a lower CWIP balance after the Wyoming-Jacksons Ferry 765 kV line and the Mountaineer scrubber were placed into service.

· Interest Expense increased $33 million primarily due to a $14 million decrease in the debt component of AFUDC resulting from AFUDC recorded in the third quarter of 2006 associated with the E&R case, a $13 million increase in interest expense from long-term debt issuances, a $4 million increase in the interest on the Virginia provision for revenue collected subject to refund and a $3 million increase in interest expense from the Utility Money Pool.
· Income Tax Expense decreased $13 million primarily due to a decrease in pretax book income and state income taxes partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

<u>Financial Condition</u>

Credit Ratings

The rating agencies currently have APCo 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, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,318	$ 1,741
Cash Flows From (Used For):		
Operating Activities	221,534	430,735
Investing Activities	(570,019)	(719,590)
Financing Activities	347,436	288,363
Net Decrease in Cash and Cash Equivalents	(1,049)	(492)
Cash and Cash Equivalents at End of Period	$ 1,269	$ 1,249

Operating Activities

Net Cash Flows From Operating Activities were $222 million in 2007. APCo produced Net Income of $19 million during the period and had noncash expense items of $142 million for Depreciation and Amortization and $79 million for Extraordinary Loss for the Reapplication of Regulatory Accounting for Generation and $23 million for Carrying Costs Income. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital included no significant unusual items.

Net Cash Flows From Operating Activities were $431 million in 2006. APCo 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 current period activity in working capital included no significant items.

Investing Activities

Net Cash Flows Used For Investing Activities during 2007 and 2006 primarily reflect construction expenditures of $538 million and $633 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades at power plants for both periods. In 2006, capital projects for transmission expenditures were primarily related to the Wyoming-Jacksons Ferry 765 KV line placed into service in June 2006. Environmental upgrades include the flue gas desulfurization projects at the Amos and Mountaineer plants. In February 2007, the flue gas desulfurization project was completed at the Mountaineer plant. Based upon APCo's current forecast, APCo expects construction expenditures to be approximately $200 million for the remainder of 2007, excluding AFUDC. In addition, APCo's investments in the Utility Money Pool increased by $39 million and $94 million in 2007 and 2006, respectively.

Financing Activities

Net Cash Flows From Financing Activities in 2007 were $347 million primarily due to the issuance of $75 million of Pollution Control Bonds in May 2007 and the issuance of $500 million of Senior Unsecured Notes in August 2007, net of the retirement of $125 million of Senior Unsecured Notes in June 2007. APCo also reduced its short-term borrowings from the Utility Money Pool by $35 million.

Net Cash Flows From Financing Activities were $288 million in 2006. In 2006, APCo issued $500 million in Senior Notes and $50 million in Pollution Control Bonds. APCo also retired First Mortgage Bonds of $100 million and reduced its short-term borrowings from the Utility Money Pool by $194 million. In addition, APCo received funds of $68 million related to a long-term coal purchase contract amended in March 2006.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2007 were:

<u>Issuances</u>

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	75,000	Variable	2037
Senior Unsecured Notes		250,000	5.65	2012
Senior Unsecured Notes		250,000	6.70	2037

<u>Retirements</u>

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	125,000	Variable	2007

Liquidity

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

Summary Obligation Information

A summary of contractual obligations is included in the 2006 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above and the obligations resulting from the settlement agreement regarding alleged violations of the NSR provisions of the CAA. See "Federal EPA Complaint and Notice of Violations" section of Note 4.

Significant Factors

Virginia Restructuring

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation and supply rates. These amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation and supply will return to a form of cost-based regulation in lieu of market-based rates. The legislation provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investments, (b) demand side management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments; significant return on equity enhancements for investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. The new re-regulation legislation should result in significant positive effects on APCo's future earnings and cash flows from the mandated enhanced future returns on equity, the reduction of regulatory lag from the opportunities to adjust base rates on a biennial basis and the new opportunities to request timely recovery of certain new costs not included in base rates.

Litigation and Regulatory Activity

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management 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 pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2006 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees 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 results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. 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 APCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included on the condensed consolidated balance sheet as of September 30, 2007 and the reasons for changes in total MTM value as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet As of September 30, 2007 (in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 65,385	$ 3,806	$ -	$ 69,191
Noncurrent Assets	80,970	2,240	-	83,210
Total MTM Derivative Contract Assets	146,355	6,046	-	152,401
Current Liabilities	(47,471)	(1,129)	(3,878)	(52,478)
Noncurrent Liabilities	(48,866)	(214)	(6,478)	(55,558)
Total MTM Derivative Contract Liabilities	(96,337)	(1,343)	(10,356)	(108,036)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 50,018	$ 4,703	$ (10,356)	$ 44,365

(a) See "Natural Gas Contracts with DETM" section of Note 16 of the 2006 Annual Report.

MTM Risk Management Contract Net Assets Nine Months Ended September 30, 2007 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 52,489
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(10,155)
Fair Value of New Contracts at Inception When Entered During the Period (a)	255
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	503
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	3,858
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	3,068
Total MTM Risk Management Contract Net Assets	50,018

Net Cash Flow & Fair Value Hedge Contracts		4,703
DETM Assignment (d)		(10,356)
Total MTM Risk Management Contract Net Assets at September 30, 2007	$	44,365

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 16 of the 2006 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 total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2007
(in thousands)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 3,994	$ (5,820)	$ 1,134	$ (20)	$ -	$ -	$ (712)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	1,170	17,393	13,606	10,310	-	-	42,479
Prices Based on Models and Other Valuation Methods (b)	754	660	1,027	1,685	2,112	2,013	8,251
Total	$ 5,918	$ 12,233	$ 15,767	$ 11,975	$ 2,112	$ 2,013	$ 50,018

(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 independent information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted

cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market. Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available including values determinable by other third party transactions.

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

APCo is exposed to market fluctuations in energy commodity prices impacting its power operations. Management monitors these risks on future operations and may use various commodity derivative instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

Management uses foreign currency derivatives to lock in prices on certain transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedge strategies. Management does not hedge all foreign currency.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on the Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2006 to September 30, 2007. 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, 2007
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2006	$ 5,332	$ (164)	$ (7,715)	$ (2,547)
Changes in Fair Value	3,049	(2)	(313)	2,734
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(4,788)	5	1,049	(3,734)
Ending Balance in AOCI September 30, 2007	$ 3,593	$ (161)	$ (6,979)	$ (3,547)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $740 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure 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, 2007, a near term typical change in commodity prices is not expected to have a material effect on 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, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$ 231	$ 2,328	$ 683	$ 168	$ 756	$ 1,915	$ 658	$ 358

VaR Associated with Debt Outstanding

Management utilizes 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 exposure to interest rates primarily related to long-term debt with fixed interest rates was $219 million and $153 million at September 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect 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, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended 2007	Three Months Ended 2006	Nine Months Ended 2007	Nine Months Ended 2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 639,830	$ 588,684	$ 1,740,565	$ 1,612,735
Sales to AEP Affiliates	64,099	57,177	181,015	177,557
Other	2,647	2,740	8,134	7,338
TOTAL	706,576	648,601	1,929,714	1,797,630
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	200,702	184,275	535,906	506,368
Purchased Electricity for Resale	47,430	41,027	117,708	98,622
Purchased Electricity from AEP Affiliates	171,288	130,826	443,519	356,682
Other Operation	94,190	63,149	236,944	210,206
Maintenance	49,708	53,874	146,875	138,381
Depreciation and Amortization	51,864	61,270	142,100	158,226
Taxes Other Than Income Taxes	23,561	24,464	67,811	70,355
TOTAL	638,743	558,885	1,690,863	1,538,840
OPERATING INCOME	67,833	89,716	238,851	258,790
Other Income (Expense):				
Interest Income	510	2,463	1,539	6,228
Carrying Costs Income (Expense)	8,701	(27,316)	22,817	(13,532)
Allowance for Equity Funds Used During Construction	1,084	6,748	5,442	13,307
Interest Expense	(44,980)	(27,103)	(121,758)	(89,024)
INCOME BEFORE INCOME TAXES	33,148	44,508	146,891	175,769
Income Tax Expense	9,090	13,972	49,325	61,992
INCOME BEFORE EXTRAORDINARY LOSS	24,058	30,536	97,566	113,777
Extraordinary Loss – Reapplication of Regulatory Accounting for Generation, Net of Tax	-	-	(78,763)	-
NET INCOME	24,058	30,536	18,803	113,777
Preferred Stock Dividend Requirements Including Capital Stock Expense and Other	238	238	714	714
EARNINGS APPLICABLE TO COMMON STOCK	$ 23,820	$ 30,298	$ 18,089	$ 113,063

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 260,458	$ 924,837	$ 635,016	$ (16,610)	$ 1,803,701
Common Stock Dividends			(7,500)		(7,500)
Preferred Stock Dividends			(600)		(600)
Capital Stock Expense and Other		118	(114)		4
TOTAL					1,795,605
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,007				13,014	13,014
NET INCOME			113,777		113,777
TOTAL COMPREHENSIVE INCOME					126,791
SEPTEMBER 30, 2006	$ 260,458	$ 924,955	$ 740,579	$ (3,596)	$ 1,922,396
DECEMBER 31, 2006	$ 260,458	$ 1,024,994	$ 805,513	$ (54,791)	$ 2,036,174
FIN 48 Adoption, Net of Tax			(2,685)		(2,685)
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(600)		(600)
Capital Stock Expense and Other		117	(114)		3
TOTAL					2,007,892
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $539				(1,000)	(1,000)
SFAS 158 Costs Established as a Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6,055				11,245	11,245
NET INCOME			18,803		18,803
TOTAL COMPREHENSIVE INCOME					29,048
SEPTEMBER 30, 2007	$ 260,458	$ 1,025,111	$ 795,917	$ (44,546)	$ 2,036,940

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,269	$ 2,318
Advances to Affiliates	38,573	-
Accounts Receivable:		
Customers	200,173	180,190
Affiliated Companies	79,576	98,237
Accrued Unbilled Revenues	34,668	46,281
Miscellaneous	3,366	3,400
Allowance for Uncollectible Accounts	(10,379)	(4,334)
Total Accounts Receivable	307,404	323,774
Fuel	85,468	77,077
Materials and Supplies	66,387	56,235
Risk Management Assets	69,191	105,376
Accrued Tax Benefits	8,881	3,748
Regulatory Asset for Under-Recovered Fuel Costs	-	29,526
Prepayments and Other	39,402	20,126
TOTAL	616,575	618,180
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,499,672	2,844,803
Transmission	1,663,553	1,620,512
Distribution	2,341,513	2,237,887
Other	348,901	339,450
Construction Work in Progress	678,095	957,626
Total	8,531,734	8,000,278
Accumulated Depreciation and Amortization	2,578,083	2,476,290
TOTAL - NET	5,953,651	5,523,988
OTHER NONCURRENT ASSETS		
Regulatory Assets	680,644	622,153
Long-term Risk Management Assets	83,210	88,906
Deferred Charges and Other	149,137	163,089
TOTAL	912,991	874,148
TOTAL ASSETS	$ 7,483,217	$ 7,016,316

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 34,975
Accounts Payable:		
General	218,212	296,437
Affiliated Companies	88,326	105,525
Long-term Debt Due Within One Year – Nonaffiliated	399,214	324,191
Risk Management Liabilities	52,478	81,114
Customer Deposits	56,143	56,364
Accrued Taxes	52,072	60,056
Accrued Interest	62,775	30,617
Other	109,085	142,326
TOTAL	1,038,305	1,131,605
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,547,043	2,174,473
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	55,558	64,909
Deferred Income Taxes	931,955	957,229
Regulatory Liabilities and Deferred Investment Tax Credits	502,425	309,724
Deferred Credits and Other	253,239	224,439
TOTAL	4,390,220	3,830,774
TOTAL LIABILITIES	5,428,525	4,962,379
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,752	17,763
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,025,111	1,024,994
Retained Earnings	795,917	805,513
Accumulated Other Comprehensive Income (Loss)	(44,546)	(54,791)
TOTAL	2,036,940	2,036,174
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,483,217	$ 7,016,316

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 18,803	$ 113,777
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	142,100	158,226
Deferred Income Taxes	32,021	(7,753)
Extraordinary Loss, Net of Tax	78,763	-
Carrying Costs (Income) Expense	(22,817)	13,532
Mark-to-Market of Risk Management Contracts	1,603	(3,817)
Change in Other Noncurrent Assets	(14,627)	1,714
Change in Other Noncurrent Liabilities	27,247	20,171
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(87)	24,423
Fuel, Materials and Supplies	(11,387)	3,446
Margin Deposits	(2,300)	27,103
Accounts Payable	(38,724)	22,063
Customer Deposits	(221)	(23,591)
Accrued Taxes, Net	(9,990)	43,071
Accrued Interest	28,596	30,780
Fuel Over/Under Recovery, Net	35,770	830
Other Current Assets	(17,520)	4,972
Other Current Liabilities	(25,696)	1,788
Net Cash Flows From Operating Activities	221,534	430,735
INVESTING ACTIVITIES		
Construction Expenditures	(537,930)	(633,164)
Change in Other Cash Deposits, Net	(29)	(873)
Change in Advances to Affiliates, Net	(38,573)	(93,764)
Proceeds from Sales of Assets	6,713	8,211
Other	(200)	-
Net Cash Flows Used For Investing Activities	(570,019)	(719,590)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	568,778	544,364
Change in Advances from Affiliates, Net	(34,975)	(194,133)
Retirement of Long-term Debt – Nonaffiliated	(125,009)	(100,008)
Retirement of Cumulative Preferred Stock	(9)	(16)
Principal Payments for Capital Lease Obligations	(3,316)	(4,008)
Funds From Amended Coal Contract	-	68,078
Amortization of Funds From Amended Coal Contract	(32,433)	(17,814)
Dividends Paid on Common Stock	(25,000)	(7,500)
Dividends Paid on Cumulative Preferred Stock	(600)	(600)
Net Cash Flows From Financing Activities	347,436	288,363
Net Decrease in Cash and Cash Equivalents	(1,049)	(492)
Cash and Cash Equivalents at Beginning of Period	2,318	1,741

Cash and Cash Equivalents at End of Period	$	1,269	$	1,249
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	86,199	$	51,537
Net Cash Paid for Income Taxes		6,688		12,047
Noncash Acquisitions Under Capital Leases		2,738		2,598
Construction Expenditures Included in Accounts Payable at September 30,		90,315		131,692

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

In March 2007, CSPCo and AEGCo entered into a ten-year unit power agreement (UPA) for the entire output from the Lawrenceburg Plant effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional two-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, CSPCo pays AEGCo for the capacity, depreciation, fuel, operation, maintenance and tax expenses. These payments are due regardless of the plant's operating status. Fuel, operation and maintenance payments are based on actual costs incurred. All expenses will be trued up periodically.

Results of Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Net Income
(in millions)

Third Quarter of 2006		$ 84
Changes in Gross Margin:		
Retail Margins	40	
Off-system Sales	7	
Transmission Revenues, Net	(13)	
Other	1	
Total Change in Gross Margin		35
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(27)	
Depreciation and Amortization	4	
Taxes Other Than Income Taxes	(3)	
Other Income, Net	(1)	
Interest Expense	(4)	
Total Change in Operating Expenses and Other		(31)
Income Tax Expense		(3)
Third Quarter of 2007		$ 85

Net Income remained relatively flat in the third quarter of 2007 compared to the third quarter of 2006. The key components of the $1 million increase in Net Income were a $35 million increase in Gross Margin offset by a $31 million increase in Operating Expenses and Other and a $3 million increase in Income Tax Expense.

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

- Retail Margins increased $40 million primarily due to:
  - A $35 million increase in capacity settlements due to recent plant acquisitions and changes in relative peak demands of AEP Power Pool members under the Interconnection Agreement.
  -

A $15 million increase in industrial revenue due to the addition of Ormet, a major industrial customer effective January 1, 2007. See "Ormet" section of Note 3.

- An $11 million increase in rate revenues related to a $13 million increase in CSPCo's RSP offset by a $3 million decrease related to recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The decrease in rate recovery of IGCC preconstruction costs was offset by the decreased amortization of deferred expenses in Depreciation and Amortization. CSPCo's recovery of Phase 1 of IGCC preconstruction costs ended in July 2007.

These increases were partially offset by:

- A $28 million decrease in fuel margins.

- Margins from Off-system Sales increased $7 million primarily due to higher sales volumes and power prices in the east, benefits from AEP's eastern natural gas fleet, and higher trading margins.
- Transmission Revenues, Net decreased $13 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.

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

- Other Operation and Maintenance expenses increased $27 million primarily due to:
  - A $15 million increase due to the settlement agreement regarding alleged violations of the NSR provisions of the CAA. The $15 million represents CSPCo's allocation of the settlement. See "Federal EPA Complaint and Notice of Violation" section of Note 4.
  - An $8 million increase in expenses related to CSPCo's UPA for AEGCo's Lawrenceburg Plant which began in May 2007.
  - A $7 million increase in overhead line expenses due to the 2006 recognition of a regulatory asset related to PUCO orders regarding distribution service reliability and restoration costs.
- Depreciation and Amortization decreased $4 million due to the end of amortization of IGCC preconstruction costs in 2007. The decrease in amortization of IGCC preconstruction costs was offset by a corresponding decrease in Retail Margins. CSPCo's recovery of Phase 1 of IGCC preconstruction costs ended in July 2007.
- Taxes Other Than Income Taxes increased $3 million due to increases in property taxes and state excise taxes.
- Interest Expense increased $4 million partially due to a decrease in the debt component of AFUDC.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007
Net Income
(in millions)

Nine Months Ended September 30, 2006		$ 168
Changes in Gross Margin:		
Retail Margins	134	
Off-system Sales	7	
Transmission Revenues, Net	(20)	
Other	(2)	

Total Change in Gross Margin		119
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(45)	
Depreciation and Amortization	(4)	
Taxes Other Than Income Taxes	2	
Interest Expense	(1)	
Total Change in Operating Expenses and Other		(48)
Income Tax Expense		(27)
Nine Months Ended September 30, 2007	$	212

Net Income increased $44 million to $212 million in 2007. The key driver of the increase was a $119 million increase in Gross Margin offset by a $48 million increase in Operating Expenses and Other and a $27 million increase in Income Tax Expense.

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

- Retail Margins increased $134 million primarily due to:
  - A $53 million increase in capacity settlements due to changes in relative peak demands of AEP Power Pool members under the Interconnection Agreement and recent plant acquisitions.
  - A $46 million increase in rate revenues related to a $35 million increase in CSPCo's RSP, an $8 million increase related to recovery of storm costs and a $3 million increase related to recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs was offset by the amortization of deferred expenses in Depreciation and Amortization. CSPCo's recovery of Phase 1 of IGCC preconstruction costs ended in July 2007.
  - A $36 million increase in industrial revenue primarily due to the addition of Ormet, a major industrial customer, effective January 1, 2007. See "Ormet" section of Note 3.
  - A $32 million increase in residential and commercial revenue primarily due to a 30% increase in cooling degree days and a 33% increase in heating degree days.

  These increases were partially offset by:
  - A $50 million decrease in fuel margins.
- Margins from Off-system Sales increased $7 million primarily due to higher trading margins.
- Transmission Revenues, Net decreased $20 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.
- Other revenues decreased $2 million primarily due to lower gains on sales of emission allowances.

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

- Other Operation and Maintenance expenses increased $45 million primarily due to:
  -

A $15 million increase in overhead line expenses, of which $7 million relates to the recognition in 2006 of a regulatory asset related to PUCO orders regarding distribution service reliability and restoration costs and an $8 million increase in amortization of deferred storm expenses recovered through a cost-recovery rider. The increase in amortization of deferred storm expenses was offset by a corresponding increase in Retail Margins.

· A $15 million increase due to the settlement agreement regarding alleged violations of the NSR provisions of the CAA. The $15 million represents CSPCo's allocation of the settlement. See "Federal EPA Complaint and Notice of Violation" section of Note 4.

· A $12 million increase in expenses related to CSPCo's UPA for AEGCo's Lawrenceburg Plant which began in May 2007.

· Depreciation and Amortization increased $4 million primarily due to the amortization of IGCC preconstruction costs beginning in July 2006. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins. CSPCo's recovery of Phase 1 of IGCC preconstruction costs ended in July 2007.
· Income Tax Expense increased $27 million primarily due to an increase in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See the complete discussion and analysis within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section for disclosures about risk management activities.

VaR Associated with Debt Outstanding

Management utilizes 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 exposure to interest rates primarily related to long-term debt with fixed interest rates was $79 million and $70 million at September 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended 2007	Three Months Ended 2006	Nine Months Ended 2007	Nine Months Ended 2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 553,518	$ 513,643	$ 1,446,632	$ 1,321,422
Sales to AEP Affiliates	52,331	24,806	110,700	60,337
Other	1,292	1,449	3,743	4,016
TOTAL	607,141	539,898	1,561,075	1,385,775
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	103,560	90,510	255,764	231,543
Purchased Electricity for Resale	49,619	35,449	113,765	87,902
Purchased Electricity from AEP Affiliates	107,386	102,669	278,715	272,334
Other Operation	83,625	66,188	207,300	179,993
Maintenance	24,250	14,704	73,537	56,140
Depreciation and Amortization	47,589	51,156	147,332	143,524
Taxes Other Than Income Taxes	41,382	38,586	117,760	119,875
TOTAL	457,411	399,262	1,194,173	1,091,311
OPERATING INCOME	149,730	140,636	366,902	294,464
Other Income (Expense):				
Interest Income	166	989	782	1,919
Carrying Costs Income	1,261	1,046	3,492	3,082
Allowance for Equity Funds Used During Construction	738	659	2,130	1,466
Interest Expense	(19,530)	(15,813)	(51,193)	(50,247)
INCOME BEFORE INCOME TAXES	132,365	127,517	322,113	250,684
Income Tax Expense	46,911	43,496	109,656	83,064
NET INCOME	85,454	84,021	212,457	167,620
Capital Stock Expense	39	39	118	118
EARNINGS APPLICABLE TO COMMON STOCK	$ 85,415	$ 83,982	$ 212,339	$ 167,502

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 41,026	$ 580,035	$ 361,365	$ (880)	$ 981,546
Common Stock Dividends			(67,500)		(67,500)
Capital Stock Expense		118	(118)		-
TOTAL					914,046
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,121				3,940	3,940
NET INCOME			167,620		167,620
TOTAL COMPREHENSIVE INCOME					171,560
SEPTEMBER 30, 2006	$ 41,026	$ 580,153	$ 461,367	$ 3,060	$ 1,085,606
DECEMBER 31, 2006	$ 41,026	$ 580,192	$ 456,787	$ (21,988)	$ 1,056,017
FIN 48 Adoption, Net of Tax			(3,022)		(3,022)
Common Stock Dividends			(90,000)		(90,000)
Capital Stock Expense and Other		118	(118)		-
TOTAL					962,995
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,231				(2,285)	(2,285)
NET INCOME			212,457		212,457
TOTAL COMPREHENSIVE INCOME					210,172
SEPTEMBER 30, 2007	$ 41,026	$ 580,310	$ 576,104	$ (24,273)	$ 1,173,167

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,695	$ 1,319
Other Cash Deposits	45,511	1,151
Accounts Receivable:		
Customers	53,919	49,362
Affiliated Companies	36,934	62,866
Accrued Unbilled Revenues	33,756	11,042
Miscellaneous	7,792	4,895
Allowance for Uncollectible Accounts	(842)	(546)
Total Accounts Receivable	131,559	127,619
Fuel	42,518	37,348
Materials and Supplies	36,784	31,765
Emission Allowances	3,103	3,493
Risk Management Assets	38,776	66,238
Prepayments and Other	15,305	19,719
TOTAL	315,251	288,652
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,055,590	1,896,073
Transmission	498,180	479,119
Distribution	1,538,056	1,475,758
Other	204,395	191,103
Construction Work in Progress	360,560	294,138
Total	4,656,781	4,336,191
Accumulated Depreciation and Amortization	1,672,118	1,611,043
TOTAL - NET	2,984,663	2,725,148
OTHER NONCURRENT ASSETS		
Regulatory Assets	263,054	298,304
Long-term Risk Management Assets	47,634	56,206
Deferred Charges and Other	95,464	152,379
TOTAL	406,152	506,889
TOTAL ASSETS	$ 3,706,066	$ 3,520,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 123,043	$ 696
Accounts Payable:		
General	104,217	112,431
Affiliated Companies	44,320	59,538
Long-term Debt Due Within One Year - Nonaffiliated	112,000	-
Risk Management Liabilities	29,305	49,285
Customer Deposits	41,467	34,991
Accrued Taxes	109,477	166,551
Other	74,852	58,011
TOTAL	638,681	481,503
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,030,123	1,097,322
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	31,907	40,477
Deferred Income Taxes	451,456	475,888
Regulatory Liabilities and Deferred Investment Tax Credits	171,431	179,048
Deferred Credits and Other	109,301	90,434
TOTAL	1,894,218	1,983,169
TOTAL LIABILITIES	2,532,899	2,464,672
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,310	580,192
Retained Earnings	576,104	456,787
Accumulated Other Comprehensive Income (Loss)	(24,273)	(21,988)
TOTAL	1,173,167	1,056,017
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,706,066	$ 3,520,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 212,457	$ 167,620
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	147,332	143,524
Deferred Income Taxes	(13,959)	(5,097)
Carrying Costs Income	(3,492)	(3,082)
Mark-to-Market of Risk Management Contracts	3,982	(4,502)
Deferred Property Taxes	57,890	49,518
Change in Other Noncurrent Assets	(31,329)	(24,692)
Change in Other Noncurrent Liabilities	2,713	11,752
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(13,040)	(3,374)
Fuel, Materials and Supplies	(2,332)	(8,200)
Accounts Payable	(13,336)	31,765
Customer Deposits	6,476	(14,565)
Accrued Taxes, Net	(44,295)	(8,981)
Other Current Assets	(415)	26,838
Other Current Liabilities	8,817	(2,878)
Net Cash Flows From Operating Activities	317,469	355,646
INVESTING ACTIVITIES		
Construction Expenditures	(246,130)	(207,875)
Change in Other Cash Deposits, Net	(44,360)	(1,151)
Change in Advances to Affiliates, Net	-	(60,417)
Acquisition of Darby Plant	(102,032)	-
Proceeds from Sales of Assets	1,016	1,525
Net Cash Flows Used For Investing Activities	(391,506)	(267,918)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	44,257	-
Change in Advances from Affiliates, Net	122,347	(17,609)
Principal Payments for Capital Lease Obligations	(2,191)	(2,308)
Dividends Paid on Common Stock	(90,000)	(67,500)
Net Cash Flows From (Used For) Financing Activities	74,413	(87,417)
Net Increase in Cash and Cash Equivalents	376	311
Cash and Cash Equivalents at Beginning of Period	1,319	940
Cash and Cash Equivalents at End of Period	$ 1,695	$ 1,251
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 53,464	$ 52,958
Net Cash Paid for Income Taxes	93,709	35,561
Noncash Acquisitions Under Capital Leases	1,900	2,130

Construction Expenditures Included in Accounts Payable at September 30,	34,630	22,955
Noncash Assumption of Liabilities Related to Acquisition of Darby Plant	2,339	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Net Income
(in millions)

Third Quarter of 2006		$ 35
Changes in Gross Margin:		
Retail Margins	7	
FERC Municipals and Cooperatives	14	
Off-system Sales	7	
Transmission Revenues, Net	(11)	
Total Change in Gross Margin		17
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(11)	
Depreciation and Amortization	18	
Taxes Other Than Income Taxes	(1)	
Other Income	(2)	
Interest Expense	(1)	
Total Change in Operating Expenses and Other		3
Income Tax Expense		(6)
Third Quarter of 2007		$ 49

Net Income increased $14 million to $49 million in 2007. The key drivers of the increase were a $17 million increase in Gross Margin and a $3 million decrease in Operating Expenses and Other partially offset by a $6 million increase in Income Tax Expense.

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

- Retail Margins increased $7 million primarily due to higher fuel margins of $9 million due to reactivation of the fuel clause and higher retail sales of $5 million reflecting favorable weather conditions as cooling degree days increased for both the Indiana and Michigan jurisdictions. Lower revenues from financial transmission rights, net of congestion, due to fewer constraints in the PJM market partially offset the increases.
- FERC Municipals and Cooperatives margins increased $14 million due to the addition of new municipal contracts effective January 2007 including new rates and increased customer demand.
- Margins from Off-system Sales increased $7 million primarily due to higher sales volumes and power prices in the east, benefits from AEP's eastern natural gas fleet, and higher trading margins.
-

Transmission Revenues, Net decreased $11 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to a settlement agreement regarding alleged violations of the NSR provisions of the CAA, of which $14 million was allocated to I&M. See "Federal EPA Complaint and Notice of Violation" section of Note 4.
- Depreciation and Amortization expense decreased $18 million primarily due to a settlement agreement approved by the IURC reducing depreciation rates to reflect longer estimated lives for Cook and Tanners Creek plants. See "Indiana Depreciation Study Filing" section of Note 3.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income and a decrease in amortization of investment tax credits, partially offset by changes in certain book/tax differences accounted for on a flow-through basis and state income taxes.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007
Net Income
(in millions)

Nine Months Ended September 30, 2006		$ 121
Changes in Gross Margin:		
Retail Margins	(20)	
FERC Municipals and Cooperatives	40	
Off-system Sales	9	
Transmission Revenues, Net	(12)	
Other	(4)	
Total Change in Gross Margin		13
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(31)	
Depreciation and Amortization	8	
Other Income	(4)	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(32)
Income Tax Expense		7
Nine Months Ended September 30, 2007		$ 109

Net Income decreased $12 million to $109 million in 2007. The key driver of the decrease was a $32 million increase in Operating Expenses and Other partially offset by a $13 million increase in Gross Margin and a $7 million decrease in Income Tax Expense.

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

- Retail Margins decreased $20 million primarily due to a $37 million reduction in capacity settlement revenues under the Interconnection Agreement reflecting I&M's new peak demand in July 2006 and lower revenues from financial transmission rights, net of congestion, of $21 million due to fewer constraints in the PJM market. Higher retail sales of $32 million reflecting favorable weather conditions partially offset the decreases. Heating and cooling degree days increased significantly in both the Indiana and Michigan jurisdictions.
- FERC Municipals and Cooperatives margins increased $40 million due to the addition of new municipal contracts including new rates and increased demand effective July 2006 and January 2007.
- Margins from Off-system Sales increased $9 million primarily due to higher trading margins.
- Transmission Revenues, Net decreased $12 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.

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

- Other Operation and Maintenance expenses increased $31 million primarily due to the settlement agreement regarding alleged violations of the NSR provisions of the CAA, of which $14 million was allocated to I&M, a $13 million increase in coal-fired plant maintenance expenses resulting from planned outages at Rockport and Tanners Creek plants and an $8 million increase in transmission expense primarily due to reduced credits under the Transmission Equalization Agreement. Credits decreased due to I&M's July 2006 peak and due to APCo's addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006 thus decreasing I&M's share of the transmission investment pool.
- Depreciation and Amortization expense decreased $8 million primarily due to a $14 million decrease in depreciation related to the revised depreciation rates in Indiana partially offset by an increase in amortization related to capitalized software development costs.
- Interest Expense increased $5 million primarily due to an increase in outstanding long-term debt.
- Income Tax Expense decreased $7 million primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis, partially offset by a decrease in amortization of investment tax credits.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See the complete discussion and analysis within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section for disclosures about risk management activities.

VaR Associated with Debt Outstanding

Management utilizes 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 exposure to interest rates primarily related to long-term debt with fixed interest rates was $109 million and $93 million at September 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Electric Generation, Transmission and Distribution	$ 478,907	$ 449,259	$ 1,286,223	$ 1,224,609
Sales to AEP Affiliates	56,262	54,793	186,653	223,728
Other – Affiliated	16,250	12,903	43,488	37,838
Other – Nonaffiliated	7,757	8,580	21,718	24,593
TOTAL	559,176	525,535	1,538,082	1,510,768
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	103,740	98,135	290,507	283,734
Purchased Electricity for Resale	26,580	20,450	63,830	46,993
Purchased Electricity from AEP Affiliates	96,451	92,052	249,755	259,304
Other Operation	129,439	119,661	367,483	340,666
Maintenance	58,502	56,960	146,657	142,531
Depreciation and Amortization	35,604	53,404	145,801	153,897
Taxes Other Than Income Taxes	19,704	18,472	56,936	56,343
TOTAL	470,020	459,134	1,320,969	1,283,468
OPERATING INCOME	89,156	66,401	217,113	227,300
Other Income (Expense):				
Interest Income	252	1,102	1,547	2,459
Allowance for Equity Funds Used During Construction	1,734	2,517	2,726	5,881
Interest Expense	(18,312)	(17,228)	(57,744)	(52,663)
INCOME BEFORE INCOME TAXES	72,830	52,792	163,642	182,977
Income Tax Expense	23,706	18,231	55,020	62,013
NET INCOME	49,124	34,561	108,622	120,964
Preferred Stock Dividend Requirements	85	85	255	255
EARNINGS APPLICABLE TO COMMON STOCK	$ 49,039	$ 34,476	$ 108,367	$ 120,709

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 56,584	$ 861,290	$ 305,787	$ (3,569)	$ 1,220,092
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(255)		(255)
TOTAL					1,189,837
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,712				(5,036)	(5,036)
NET INCOME			120,964		120,964
TOTAL COMPREHENSIVE INCOME					115,928
SEPTEMBER 30, 2006	$ 56,584	$ 861,290	$ 396,496	$ (8,605)	$ 1,305,765
DECEMBER 31, 2006	$ 56,584	$ 861,290	$ 386,616	$ (15,051)	$ 1,289,439
FIN 48 Adoption, Net of Tax			327		327
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(255)		(255)
Gain on Reacquired Preferred Stock		1			1
TOTAL					1,259,512
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $941				(1,747)	(1,747)
NET INCOME			108,622		108,622
TOTAL COMPREHENSIVE INCOME					106,875
SEPTEMBER 30, 2007	$ 56,584	$ 861,291	$ 465,310	$ (16,798)	$ 1,366,387

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,190	$ 1,369
Accounts Receivable:		
Customers	74,743	82,102
Affiliated Companies	61,771	108,288
Accrued Unbilled Revenues	12,424	2,206
Miscellaneous	1,627	1,838
Allowance for Uncollectible Accounts	(863)	(601)
Total Accounts Receivable	149,702	193,833
Fuel	48,261	64,669
Materials and Supplies	136,332	129,953
Risk Management Assets	37,351	69,752
Accrued Tax Benefits	177	27,378
Prepayments and Other	17,968	15,170
TOTAL	391,981	502,124
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,402,220	3,363,813
Transmission	1,067,434	1,047,264
Distribution	1,180,230	1,102,033
Other (including nuclear fuel and coal mining)	558,168	529,727
Construction Work in Progress	179,597	183,893
Total	6,387,649	6,226,730
Accumulated Depreciation, Depletion and Amortization	3,003,588	2,914,131
TOTAL - NET	3,384,061	3,312,599
OTHER NONCURRENT ASSETS		
Regulatory Assets	282,020	314,805
Spent Nuclear Fuel and Decommissioning Trusts	1,314,892	1,248,319
Long-term Risk Management Assets	45,810	59,137
Deferred Charges and Other	92,710	109,453
TOTAL	1,735,432	1,731,714
TOTAL ASSETS	$ 5,511,474	$ 5,546,437

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 24,234	$ 91,173
Accounts Payable:		
General	118,010	146,733
Affiliated Companies	44,772	65,497
Long-term Debt Due Within One Year – Nonaffiliated	-	50,000
Risk Management Liabilities	28,340	52,083
Customer Deposits	31,498	34,946
Accrued Taxes	69,302	59,652
Other	133,966	128,461
TOTAL	450,122	628,545
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,564,811	1,505,135
Long-term Risk Management Liabilities	30,717	42,641
Deferred Income Taxes	305,429	335,000
Regulatory Liabilities and Deferred Investment Tax Credits	757,136	753,402
Asset Retirement Obligations	841,791	809,853
Deferred Credits and Other	187,001	174,340
TOTAL	3,686,885	3,620,371
TOTAL LIABILITIES	4,137,007	4,248,916
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,080	8,082
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,291	861,290
Retained Earnings	465,310	386,616
Accumulated Other Comprehensive Income (Loss)	(16,798)	(15,051)
TOTAL	1,366,387	1,289,439
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,511,474	$ 5,546,437

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 108,622	$ 120,964
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	145,801	153,897
Deferred Income Taxes	(9,235)	7,734
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	14,450	(20,673)
Mark-to-Market of Risk Management Contracts	6,226	(4,915)
Amortization of Nuclear Fuel	48,360	37,839
Change in Other Noncurrent Assets	14,437	16,508
Change in Other Noncurrent Liabilities	33,995	35,920
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	34,569	37,368
Fuel, Materials and Supplies	14,584	(20,665)
Accounts Payable	(27,015)	29,483
Customer Deposits	(3,448)	(14,315)
Accrued Taxes, Net	41,243	28,292
Other Current Assets	(3,459)	20,997
Other Current Liabilities	2,282	25,489
Net Cash Flows From Operating Activities	421,412	453,923
INVESTING ACTIVITIES		
Construction Expenditures	(191,110)	(240,806)
Purchases of Investment Securities	(561,509)	(559,803)
Sales of Investment Securities	505,620	517,017
Acquisitions of Nuclear Fuel	(73,112)	(72,614)
Other	670	3,344
Net Cash Flows Used For Investing Activities	(319,441)	(352,862)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	49,745
Change in Advances from Affiliates, Net	(66,939)	(66,086)
Retirement of Long-term Debt – Nonaffiliated	-	(50,000)
Retirement of Cumulative Preferred Stock	(2)	(1)
Principal Payments for Capital Lease Obligations	(3,954)	(4,612)
Dividends Paid on Common Stock	(30,000)	(30,000)
Dividends Paid on Cumulative Preferred Stock	(255)	(255)
Net Cash Flows Used For Financing Activities	(101,150)	(101,209)
Net Increase (Decrease) in Cash and Cash Equivalents	821	(148)
Cash and Cash Equivalents at Beginning of Period	1,369	854
Cash and Cash Equivalents at End of Period	$ 2,190	$ 706
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 49,628	$ 37,708

Net Cash Paid for Income Taxes	14,395	20,180
Noncash Acquisitions Under Capital Leases	5,847	4,359
Construction Expenditures Included in Accounts Payable at September 30,	23,935	29,755
Acquisition of Nuclear Fuel in Accounts Payable at September 30,	691	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Net Income
(in millions)

Third Quarter of 2006		$ 83
Changes in Gross Margin:		
Retail Margins	30	
Off-system Sales	(7)	
Transmission Revenues, Net	(15)	
Other	(1)	
Total Change in Gross Margin		7
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(4)	
Depreciation and Amortization	(2)	
Other Income, Net	(1)	
Interest Expense	(11)	
Total Change in Operating Expenses and Other		(18)
Income Tax Expense		3
Third Quarter of 2007		$ 75

Net Income decreased $8 million to $75 million in 2007. The key driver of the decrease was an $18 million increase in Operating Expenses and Other offset by a $7 million increase in Gross Margin and a $3 million decrease in Income Tax Expense.

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

- Retail Margins increased $30 million partially due to a $13 million increase in industrial revenue primarily due to the addition of Ormet, a major industrial customer, effective January 1, 2007. See "Ormet" section of Note 3. Retail Margins also increased due to a $3 million increase in rate revenues primarily related to an $8 million increase in OPCo's RSP partially offset by a $3 million decrease related to rate recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The decrease in rate recovery of IGCC preconstruction costs was offset by the decreased amortization of deferred expenses in Depreciation and Amortization.
- Margins from Off-system Sales decreased $7 million primarily due to a $10 million decrease related to OPCo's purchase power and sale agreement with Dow Chemical Company (Dow) which ended in November 2006 and a decrease in OPCo's allocated share of off-system sales revenue due to an affiliate's new peak. These decreases were offset by higher sales volumes and power prices in the east, benefits from AEP's eastern natural gas fleet, and higher trading margins.
- Transmission Revenues, Net decreased $15 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of

Note 3.

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

- Other Operation and Maintenance expenses increased $4 million primarily due to:
  - A $17 million increase due to the settlement agreement regarding alleged violations of the NSR provisions of the CAA. The $17 million represents OPCo's allocation of the settlement. See "Federal EPA Complaint and Notice of Violation" section of Note 4.
  - A $7 million increase in overhead line expenses due to the 2006 recognition of a regulatory asset related to PUCO orders regarding distribution service reliability and restoration costs.

  These increases were partially offset by:
  - A $10 million decrease due to the absence of maintenance and rental expenses related to OPCo's purchase power and sale agreement with Dow which ended in November 2006. The decrease in Other Operation and Maintenance expenses related to Dow were offset by a corresponding decrease in margins from Off-system Sales.
  - A $3 million decrease in maintenance from planned and forced outages at the Muskingum River and Kammer Plants related to boiler tube inspections in 2006.
- Depreciation and Amortization increased $2 million primarily due to a $7 million increase in depreciation related to environmental improvements placed in service at the Mitchell Plant. This increase was offset by decreased amortization of IGCC preconstruction costs of $3 million and a $2 million amortization of a regulatory liability related to Ormet. See "Ormet" section of Note 3. The decrease in amortization of IGCC preconstruction costs was offset by a corresponding decrease in Retail Margins.
- Interest Expense increased $11 million due to additional long-term debt and a decrease in the debt component of AFUDC as a result of Mitchell Plant environmental improvements placed in service.
- Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income offset by changes in certain book/tax differences accounted for on a flow-through basis.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007
Net Income
(in millions)

Nine Months Ended September 30, 2006		$ 202
Changes in Gross Margin:		
Retail Margins	152	
Off-system Sales	(23)	
Transmission Revenues, Net	(26)	
Other	(16)	
Total Change in Gross Margin		87
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	1	
Depreciation and Amortization	(14)	
Taxes Other Than Income Taxes	(2)	
Other Income, Net	(1)	

Interest Expense	(23)	
Total Change in Operating Expenses and Other		(39)
Income Tax Expense		(21)
Nine Months Ended September 30, 2007		$ 229

Net Income increased $27 million to $229 million in 2007. The key driver of the increase was an $87 million increase in Gross Margin offset by a $39 million increase in Operating Expenses and Other and a $21 million increase in Income Tax Expense.

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

- Retail Margins increased $152 million primarily due to the following:
  - A $42 million increase in capacity settlements under the Interconnection Agreement related to certain affiliates' peaks and the June 2006 expiration of OPCo's supplemental capacity and energy obligation to Buckeye Power, Inc. under the Cardinal Station Agreement.
  - A $38 million increase in rate revenues primarily related to a $26 million increase in OPCo's RSP, a $9 million increase related to rate recovery of storm costs and a $3 million increase related to rate recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs was offset by the amortization of deferred expenses in Depreciation and Amortization.
  - A $31 million increase in industrial revenue due to the addition of Ormet, a major industrial customer, effective January 1, 2007. See "Ormet" section of Note 3.
  - A $20 million increase in residential and commercial revenue primarily due to a 26% increase in cooling degree days and a 27% increase in heating degree days.
- Margins from Off-system Sales decreased $23 million primarily due to a decrease in OPCo's allocated share of off-system sales revenue due to an affiliate's new peak and a $20 million decrease related to OPCo's purchase power and sale agreement with Dow Chemical Company (Dow) which ended in November 2006. Higher trading margins helped to offset a portion of the decrease over last year.
- Transmission Revenues, Net decreased $26 million primarily due to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See "PJM Marginal-Loss Pricing" section of Note 3.
- Other revenues decreased $16 million primarily due to a $7 million decrease related to the April 2006 expiration of an obligation to sell supplemental capacity and energy to Buckeye Power, Inc. under the Cardinal Station Agreement and a $5 million decrease in gains on sales of emission allowances.

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

- Other Operation and Maintenance expenses decreased $1 million primarily due to the following:
  - A $21 million decrease in maintenance from planned and forced outages at the Muskingum River, Kammer and Sporn Plants related to boiler tube inspections in 2006.
  -

A $20 million decrease in maintenance and rental expenses related to OPCo's purchase power and sale agreement with Dow which ended in November 2006. This decrease was offset by a corresponding decrease in margins from Off-system Sales.

These decreases were partially offset by:

- A $17 million increase due to the settlement agreement regarding alleged violations of the NSR provisions of the CAA. See "Federal EPA Complaint and Notice of Violation" section of Note 4.
- A $13 million increase in overhead line expenses due to the 2006 recognition of a regulatory asset related to PUCO orders regarding distribution service reliability and restoration costs and the amortization of deferred storm expenses recovered through a cost-recovery rider. The increase in the amortization of deferred storm expenses was offset by a corresponding increase in Retail Margins.
- A $7 million increase in removal costs related to planned and forced outages at the Gavin, Mitchell and Cardinal Plants.

- Depreciation and Amortization increased $14 million primarily due to a $16 million increase in depreciation related to environmental improvements placed in service at the Mitchell Plant and the amortization of IGCC preconstruction costs of $3 million in 2007. These increases were partially offset by a $5 million decrease related to the amortization of a regulatory liability related to Ormet. See "Ormet" section of Note 3. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Interest Expense increased $23 million primarily due to additional long-term debt.
- Income Tax Expense increased $21 million primarily due to an increase in pretax book income and state income taxes.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the nine months ended September 30, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,625	$ 1,240
Cash Flows From (Used For):		
Operating Activities	402,980	470,180
Investing Activities	(743,260)	(703,550)
Financing Activities	351,381	233,455
Net Increase in Cash and Cash Equivalents	11,101	85
Cash and Cash Equivalents at End of Period	$ 12,726	$ 1,325

Operating Activities

Net Cash Flows From Operating Activities were $403 million in 2007. OPCo produced Net Income of $229 million during the period and a noncash expense item of $253 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital included two significant items. Accounts Payable had a $60 million cash outflow partially due to emission allowance payments in January 2007, reduced accruals for Mitchell Plant environmental projects that went into service in 2007 and timing differences for payments to affiliates. Accounts Receivable, Net had a $33 million cash outflow partially due to the timing of collections of receivables.

Net Cash Flows From Operating Activities were $470 million in 2006. OPCo produced Net Income of $202 million during the period and a noncash expense item of $239 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 primarily included two significant items. Accounts Receivable, Net had a $78 million cash inflow primarily due to the collection of receivables related to power sales to affiliates. Accounts Payable had a $45 million cash outflow primarily due to timing differences for payments to affiliates related to emission allowances and the AEP Power Pool.

Investing Activities

Net Cash Flows Used For Investing Activities were $743 million and $704 million in 2007 and 2006, respectively. Construction Expenditures were $751 million and $715 million in 2007 and 2006, respectively, primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and flue gas desulfurization projects at the Cardinal, Amos and Mitchell Plants. In January 2007, environmental upgrades were completed for Unit 1 and 2 at the Mitchell Plant. Based upon OPCo’s current forecast, OPCo expects construction expenditures to be approximately $150 million for the remainder of 2007, excluding AFUDC.

Financing Activities

Net Cash Flows From Financing Activities were $351 million in 2007. OPCo issued $400 million of Senior Unsecured Notes and $65 million of Pollution Control Bonds. OPCo reduced borrowings by $96 million from the Utility Money Pool.

Net Cash Flows From Financing Activities were $233 million for 2006. OPCo issued $350 million of Senior Unsecured Notes and $65 million of Pollution Control Bonds. OPCo retired Notes Payable-Affiliated of $200 million. OPCo received a Capital Contribution from Parent of $70 million.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2007 were:

Issuances

Type of Debt	Principal Amount (in thousands)		Interest Rate (%)	Due Date
Pollution Control Bonds	$	65,000	4.90	2037
Senior Unsecured Notes		400,000	Variable	2010

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Nonaffiliated	$ 2,927	6.81	2008
Notes Payable – Nonaffiliated	6,000	6.27	2009

Liquidity

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

Summary Obligation Information

A summary of contractual obligations is included in the 2006 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above and the obligations resulting from the settlement agreement regarding alleged violations of the NSR provisions of the CAA. See "Federal EPA Complaint and Notice of Violations" section of Note 4.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management 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 pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2006 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees 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 results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. 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 OPCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in the condensed consolidated balance sheet as of September 30, 2007 and the reasons for changes in total MTM value as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2007
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 45,622	$ 1,401	$ -	$ 47,023
Noncurrent Assets	55,412	987	-	56,399
Total MTM Derivative Contract Assets	101,034	2,388	-	103,422
Current Liabilities	(35,178)	(229)	(2,616)	(38,023)
Noncurrent Liabilities	(33,907)	(402)	(4,370)	(38,679)
Total MTM Derivative Contract Liabilities	(69,085)	(631)	(6,986)	(76,702)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 31,949	$ 1,757	$ (6,986)	$ 26,720

(a) See "Natural Gas Contracts with DETM" section of Note 16 in the 2006 Annual Report.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2007
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 33,042
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(6,663)
Fair Value of New Contracts at Inception When Entered During the Period (a)	3,267
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	340
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	2,411
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(448)
Total MTM Risk Management Contract Net Assets	31,949
Net Cash Flow Hedge Contracts	1,757

DETM Assignment (d)		(6,986)
Total MTM Risk Management Contract Net Assets at September 30, 2007	$	26,720

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(d) See "Natural Gas Contracts with DETM" section of Note 16 in the 2006 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 total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2007
(in thousands)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 2,927	$ (4,308)	$ 857	$ (30)	$ -	$ -	$ (554)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	110	11,983	9,396	6,954	-	-	28,443
Prices Based on Models and Other Valuation Methods (b)	42	(557)	661	1,132	1,424	1,358	4,060
Total	$ 3,079	$ 7,118	$ 10,914	$ 8,056	$ 1,424	$ 1,358	$ 31,949

(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 independent information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for

underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market. Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available including values determinable by other third party transactions.

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

OPCo is exposed to market fluctuations in energy commodity prices impacting power operations. Management monitors these risks on future operations and may use various commodity derivative instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

Management uses foreign currency derivatives to lock in prices on certain transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedge strategies. Management does not hedge all foreign currency.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on the Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2006 to September 30, 2007. 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, 2007
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2006	$ 4,040	$ (331)	$ 3,553	$ 7,262
Changes in Fair Value	537	(4)	(139)	394
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(3,280)	10	(610)	(3,880)
Ending Balance in AOCI September 30, 2007	$ 1,297	$ (325)	$ 2,804	$ 3,776

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,576 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure 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, 2007, a near term typical change in commodity prices is not expected to have a material effect on 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, 2007 (in thousands)				**Twelve Months Ended December 31, 2006 (in thousands)**			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$ 208	$ 2,054	$ 594	$ 159	$ 573	$ 1,451	$ 500	$ 271

VaR Associated with Debt Outstanding

Management utilizes 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 exposure to interest rates primarily related to long-term debt with fixed interest rates was $138 million and $110 million at September 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended 2007	Three Months Ended 2006	Nine Months Ended 2007	Nine Months Ended 2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 543,404	$ 558,490	$ 1,516,383	$ 1,556,193
Sales to AEP Affiliates	205,193	198,640	564,292	502,547
Other - Affiliated	5,749	4,400	16,604	11,975
Other - Nonaffiliated	3,397	3,378	10,838	12,806
TOTAL	757,743	764,908	2,108,117	2,083,521
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	254,310	280,593	653,941	727,261
Purchased Electricity for Resale	33,178	28,324	85,900	76,351
Purchased Electricity from AEP Affiliates	43,147	35,423	92,858	92,086
Other Operation	102,850	100,265	292,809	286,083
Maintenance	45,663	44,503	155,428	163,443
Depreciation and Amortization	84,400	82,755	253,455	239,431
Taxes Other Than Income Taxes	47,506	47,945	146,211	143,634
TOTAL	611,054	619,808	1,680,602	1,728,289
OPERATING INCOME	146,689	145,100	427,515	355,232
Other Income (Expense):				
Interest Income	108	840	992	2,072
Carrying Costs Income	3,644	3,502	10,779	10,336
Allowance for Equity Funds Used During Construction	590	755	1,607	1,891
Interest Expense	(36,262)	(24,610)	(95,927)	(72,461)
INCOME BEFORE INCOME TAXES	114,769	125,587	344,966	297,070
Income Tax Expense	39,507	42,245	116,103	95,297
NET INCOME	75,262	83,342	228,863	201,773
Preferred Stock Dividend Requirements	183	183	549	549
EARNINGS APPLICABLE TO COMMON STOCK	$ 75,079	$ 83,159	$ 228,314	$ 201,224

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 321,201	$ 466,637	$ 979,354	$ 755	$ 1,767,947
Capital Contribution From Parent		70,000			70,000
Preferred Stock Dividends			(549)		(549)
Gain on Reacquired Preferred Stock		2			2
TOTAL					1,837,400
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,393				6,300	6,300
NET INCOME			201,773		201,773
TOTAL COMPREHENSIVE INCOME					208,073
SEPTEMBER 30, 2006	$ 321,201	$ 536,639	$ 1,180,578	$ 7,055	$ 2,045,473
DECEMBER 31, 2006	$ 321,201	$ 536,639	$ 1,207,265	$ (56,763)	$ 2,008,342
FIN 48 Adoption, Net of Tax			(5,380)		(5,380)
Preferred Stock Dividends			(549)		(549)
TOTAL					2,002,413
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,878				(3,486)	(3,486)
NET INCOME			228,863		228,863
TOTAL COMPREHENSIVE INCOME					225,377
SEPTEMBER 30, 2007	$ 321,201	$ 536,639	$ 1,430,199	$ (60,249)	$ 2,227,790

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12,726	$ 1,625
Accounts Receivable:		
Customers	96,217	86,116
Affiliated Companies	102,771	108,214
Accrued Unbilled Revenues	28,193	10,106
Miscellaneous	1,235	1,819
Allowance for Uncollectible Accounts	(1,079)	(824)
Total Accounts Receivable	227,337	205,431
Fuel	125,583	120,441
Materials and Supplies	82,377	74,840
Emission Allowances	6,218	10,388
Risk Management Assets	47,023	86,947
Accrued Tax Benefits	8,476	22,909
Prepayments and Other	27,332	18,416
TOTAL	537,072	540,997
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	5,553,893	4,413,340
Transmission	1,059,631	1,030,934
Distribution	1,372,724	1,322,103
Other	312,305	299,637
Construction Work in Progress	676,841	1,339,631
Total	8,975,394	8,405,645
Accumulated Depreciation and Amortization	2,921,494	2,836,584
TOTAL - NET	6,053,900	5,569,061
OTHER NONCURRENT ASSETS		
Regulatory Assets	354,499	414,180
Long-term Risk Management Assets	56,399	70,092
Deferred Charges and Other	176,964	224,403
TOTAL	587,862	708,675
TOTAL ASSETS	$ 7,178,834	$ 6,818,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 85,341	$ 181,281
Accounts Payable:		
General	136,467	250,025
Affiliated Companies	104,106	145,197
Short-term Debt – Nonaffiliated	2,097	1,203
Long-term Debt Due Within One Year – Nonaffiliated	22,390	17,854
Risk Management Liabilities	38,023	73,386
Customer Deposits	36,407	31,465
Accrued Taxes	126,995	165,338
Accrued Interest	45,151	35,497
Other	119,987	123,631
TOTAL	716,964	1,024,877
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,635,957	2,183,887
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	38,679	52,929
Deferred Income Taxes	895,839	911,221
Regulatory Liabilities and Deferred Investment Tax Credits	167,182	185,895
Deferred Credits and Other	263,136	219,127
TOTAL	4,200,793	3,753,059
TOTAL LIABILITIES	4,917,757	4,777,936
Minority Interest	16,660	15,825
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,627	16,630
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	536,639	536,639
Retained Earnings	1,430,199	1,207,265
Accumulated Other Comprehensive Income (Loss)	(60,249)	(56,763)
TOTAL	2,227,790	2,008,342
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,178,834	$ 6,818,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 228,863	$ 201,773
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	253,455	239,431
Deferred Income Taxes	3,938	(18,399)
Carrying Costs Income	(10,779)	(10,336)
Mark-to-Market of Risk Management Contracts	(424)	668
Deferred Property Taxes	54,036	54,073
Change in Other Noncurrent Assets	(21,882)	1,732
Change in Other Noncurrent Liabilities	8,026	15,923
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(32,723)	78,307
Fuel, Materials and Supplies	(1,245)	(25,375)
Accounts Payable	(59,925)	(44,817)
Accrued Taxes, Net	(19,997)	(27,733)
Other Current Assets	(10,544)	36,333
Other Current Liabilities	12,181	(31,400)
Net Cash Flows From Operating Activities	402,980	470,180
INVESTING ACTIVITIES		
Construction Expenditures	(751,161)	(715,200)
Proceeds From Sales of Assets	7,924	13,301
Other	(23)	(1,651)
Net Cash Flows Used For Investing Activities	(743,260)	(703,550)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	70,000
Issuance of Long-term Debt – Nonaffiliated	461,324	405,841
Change in Short-term Debt, Net – Nonaffiliated	895	(3,264)
Change in Advances from Affiliates, Net	(95,940)	(21,908)
Retirement of Long-term Debt – Nonaffiliated	(8,927)	(10,890)
Retirement of Long-term Debt – Affiliated	-	(200,000)
Retirement of Cumulative Preferred Stock	(2)	(7)
Principal Payments for Capital Lease Obligations	(5,420)	(5,768)
Dividends Paid on Cumulative Preferred Stock	(549)	(549)
Net Cash Flows From Financing Activities	351,381	233,455
Net Increase in Cash and Cash Equivalents	11,101	85
Cash and Cash Equivalents at Beginning of Period	1,625	1,240
Cash and Cash Equivalents at End of Period	$ 12,726	$ 1,325
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 85,851	$ 71,666
Net Cash Paid for Income Taxes	61,459	72,175

Noncash Acquisitions Under Capital Leases	1,620	2,529
Construction Expenditures Included in Accounts Payable at September 30,	42,055	117,638

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

The condensed notes to OPCo'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 OPCo.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

Results of Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Net Income
(in millions)

Third Quarter of 2006		$ 42
Changes in Gross Margin:		
Retail and Off-system Sales Margins	1	
Transmission Revenues, Net	1	
Other	2	
Total Change in Gross Margin		4
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(3)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(6)	
Interest Expense	(1)	
Total Change in Operating Expenses and Other		(12)
Income Tax Expense		3
Third Quarter of 2007		$ 37

Net Income decreased $5 million to $37 million in 2007. The key drivers of the decrease were a $12 million increase in Operating Expenses and Other, partially offset by a $4 million increase in Gross Margin and a $3 million decrease in Income Tax Expense .

The major components of the 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 and Off-system Sales Margins increased $1 million primarily due to an increase in retail margins attributable to new base rates partially offset by a reduction in off-system sales volumes.
- Other revenues increased $2 million primarily due to higher gains on sales of emission allowances.

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

- Other Operation and Maintenance expenses increased $3 million primarily due to an increase in transmission expense resulting from higher SPP administration fees and transmission services from other utilities.
- Taxes Other Than Income Taxes increased $6 million primarily due to a sales and use tax adjustment recorded in 2006.

· Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007
Net Income
(in millions)

Nine Months Ended September 30, 2006		$	51
Changes in Gross Margin:			
Retail and Off-system Sales Margins	3		
Transmission Revenues, Net	2		
Other	(1)		
Total Change in Gross Margin			4
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(32)		
Depreciation and Amortization	(5)		
Taxes Other than Income Taxes	(6)		
Interest Expense	(7)		
Total Change in Operating Expenses and Other			(50)
Income Tax Expense			17
Nine Months Ended September 30, 2007		$	22

Net Income decreased $29 million to $22 million in 2007. The key drivers of the decrease were a $50 million increase in Operating Expenses and Other, partially offset by a $17 million decrease in Income Tax Expense and a $4 million increase in Gross Margin.

The major components of the 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 and Off-system Sales Margins increased $3 million primarily due to an increase in retail margins attributable to new base rates.

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

· Other Operation and Maintenance expenses increased $32 million primarily due to an $18 million increase in distribution expense resulting primarily from the January 2007 ice storm and a $9 million increase in generation expense primarily due to scheduled maintenance outages. Transmission expense increased $5 million primarily due to $4 million in higher SPP administration fees and transmission services from other utilities and $1 million in higher overhead line maintenance.
· Depreciation and Amortization increased $5 million primarily due to higher depreciable asset balances.
· Taxes Other Than Income Taxes increased $6 million primarily due to a sales and use tax adjustment recorded in 2006.

- Interest Expense increased $7 million primarily due to increased borrowings.
- Income Tax Expense decreased $17 million primarily due to a decrease in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 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.

Adoption of New Accounting Pronouncements

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See the complete discussion and analysis within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section for disclosures about risk management activities.

VaR Associated with Debt Outstanding

Management utilizes 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 exposure to interest rates primarily related to long-term debt with fixed interest rates was $42 million and $39 million at September 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2007	2006	2007	2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 433,737	$ 443,593	$ 1,028,637	$ 1,116,507
Sales to AEP Affiliates	12,737	14,034	53,605	40,647
Other	1,562	814	2,746	3,062
TOTAL	448,036	458,441	1,084,988	1,160,216
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	182,680	202,836	438,828	566,985
Purchased Electricity for Resale	75,875	68,547	213,429	158,122
Purchased Electricity from AEP Affiliates	16,216	17,706	48,679	54,817
Other Operation	44,030	40,644	127,382	117,385
Maintenance	24,128	25,072	89,390	67,412
Depreciation and Amortization	24,430	22,215	70,128	65,060
Taxes Other Than Income Taxes	10,007	3,844	30,191	23,997
TOTAL	377,366	380,864	1,018,027	1,053,778
OPERATING INCOME	70,670	77,577	66,961	106,438
Other Income	1,086	1,050	2,294	1,830
Interest Expense	(12,381)	(10,954)	(36,549)	(29,723)
INCOME BEFORE INCOME TAXES	59,375	67,673	32,706	78,545
Income Tax Expense	22,804	25,650	10,266	27,241
NET INCOME	36,571	42,023	22,440	51,304
Preferred Stock Dividend Requirements	53	53	159	159
EARNINGS APPLICABLE TO COMMON STOCK	$ 36,518	$ 41,970	$ 22,281	$ 51,145

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 157,230	$ 230,016	$ 162,615	$ (1,264)	$ 548,597
Preferred Stock Dividends			(159)		(159)
TOTAL					548,438
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2				(4)	(4)
NET INCOME			51,304		51,304
TOTAL COMPREHENSIVE INCOME					51,300
SEPTEMBER 30, 2006	$ 157,230	$ 230,016	$ 213,760	$ (1,268)	$ 599,738
DECEMBER 31, 2006	$ 157,230	$ 230,016	$ 199,262	$ (1,070)	$ 585,438
FIN 48 Adoption, Net of Tax			(386)		(386)
Capital Contributions from Parent		60,000			60,000
Preferred Stock Dividends			(159)		(159)
TOTAL					644,893
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $74				137	137
NET INCOME			22,440		22,440
TOTAL COMPREHENSIVE INCOME					22,577
SEPTEMBER 30, 2007	$ 157,230	$ 290,016	$ 221,157	$ (933)	$ 667,470

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,490	$ 1,651
Accounts Receivable:		
Customers	42,848	70,319
Affiliated Companies	94,920	73,318
Miscellaneous	47,769	10,270
Allowance for Uncollectible Accounts	(18)	(5)
Total Accounts Receivable	185,519	153,902
Fuel	17,922	20,082
Materials and Supplies	52,655	48,375
Risk Management Assets	43,004	100,802
Accrued Tax Benefits	9,499	4,679
Regulatory Asset for Under-Recovered Fuel Costs	15,817	7,557
Margin Deposits	2,526	35,270
Prepayments and Other	4,424	5,732
TOTAL	332,856	378,050
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,106,110	1,091,910
Transmission	556,760	503,638
Distribution	1,311,738	1,215,236
Other	243,575	234,227
Construction Work in Progress	158,499	141,283
Total	3,376,682	3,186,294
Accumulated Depreciation and Amortization	1,212,294	1,187,107
TOTAL - NET	2,164,388	1,999,187
OTHER NONCURRENT ASSETS		
Regulatory Assets	156,708	142,905
Long-term Risk Management Assets	5,329	17,066
Employee Benefits and Pension Assets	28,962	30,161
Deferred Charges and Other	17,386	11,677
TOTAL	208,385	201,809
TOTAL ASSETS	$ 2,705,629	$ 2,579,046

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 187,492	$ 76,323
Accounts Payable:		
General	173,364	165,618
Affiliated Companies	69,044	65,134
Risk Management Liabilities	31,867	88,469
Customer Deposits	42,891	51,335
Accrued Taxes	43,540	19,984
Other	32,376	58,651
TOTAL	580,574	525,514
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	670,132	669,998
Long-term Risk Management Liabilities	5,483	11,448
Deferred Income Taxes	430,307	414,197
Regulatory Liabilities and Deferred Investment Tax Credits	284,970	315,584
Deferred Credits and Other	61,431	51,605
TOTAL	1,452,323	1,462,832
TOTAL LIABILITIES	2,032,897	1,988,346
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	290,016	230,016
Retained Earnings	221,157	199,262
Accumulated Other Comprehensive Income (Loss)	(933)	(1,070)
TOTAL	667,470	585,438
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,705,629	$ 2,579,046

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 22,440	$ 51,304
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	70,128	65,060
Deferred Income Taxes	23,220	(18,661)
Mark-to-Market of Risk Management Contracts	6,968	8,901
Deferred Property Taxes	(8,353)	(8,098)
Change in Other Noncurrent Assets	(10,050)	17,850
Change in Other Noncurrent Liabilities	(31,165)	(24,838)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(31,617)	(2,389)
Fuel, Materials and Supplies	(2,110)	(6,990)
Margin Deposits	32,744	(25,811)
Accounts Payable	10,226	1,585
Customer Deposits	(8,444)	(2,737)
Accrued Taxes, Net	19,725	48,845
Fuel Over/Under Recovery, Net	(8,260)	76,938
Other Current Assets	177	(3,828)
Other Current Liabilities	(23,587)	(13,755)
Net Cash Flows From Operating Activities	62,042	163,376
INVESTING ACTIVITIES		
Construction Expenditures	(235,089)	(140,998)
Change in Advances to Affiliates, Net	-	(43,538)
Other	3,173	6
Net Cash Flows Used For Investing Activities	(231,916)	(184,530)
FINANCING ACTIVITIES		
Capital Contributions from Parent	60,000	-
Issuance of Long-term Debt – Nonaffiliated	12,488	148,747
Change in Advances from Affiliates, Net	111,169	(75,883)
Retirement of Long-term Debt – Affiliated	(12,660)	(50,000)
Principal Payments for Capital Lease Obligations	(1,125)	(794)
Dividends Paid on Cumulative Preferred Stock	(159)	(159)
Net Cash Flows From Financing Activities	169,713	21,911
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	757
Cash and Cash Equivalents at Beginning of Period	1,651	1,520
Cash and Cash Equivalents at End of Period	$ 1,490	$ 2,277
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 34,427	$ 25,491
Net Cash Paid (Received) for Income Taxes	(18,004)	7,471
Noncash Acquisitions Under Capital Leases	600	2,639

Construction Expenditures Included in Accounts Payable at September 30,	16,358	6,591

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Third Quarter of 2007 Compared to Third Quarter of 2006

Reconciliation of Third Quarter of 2006 to Third Quarter of 2007
Net Income
(in millions)

Third Quarter of 2006		$ 50
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	(1)	
Transmission Revenues, Net	1	
Other	(7)	
Total Change in Gross Margin		(7)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(7)	
Depreciation and Amortization	(1)	
Other Income	3	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		8
Third Quarter of 2007		$ 44

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

Net Income decreased $6 million to $44 million in 2007. The key drivers of the decrease were a $7 million decrease in Gross Margin and a $7 million increase in Operating Expenses and Other, partially offset by an $8 million decrease in Income Tax Expense.

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

- Other revenues decreased $7 million primarily due to a $5 million decrease in gains on sales of emission allowances and a $1 million decrease in revenue from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to outside parties. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to a $5 million increase in transmission expenses resulting from higher SPP administration fees and transmission services from other utilities, and a $3 million increase in generation expenses due to planned and forced outages at the Welsh, Dolet Hills, Flint Creek, Knox Lee and Pirkey Plants. These increases were partially offset by a $1 million decrease in expenses primarily resulting from decreased coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, due to planned and forced outages at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation, a nonaffiliated entity.

- Other Income increased $3 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects.
- Interest Expense increased $2 million primarily due to $4 million of interest related to increased long-term debt partially offset by a $2 million increase in the debt component of AFUDC due to new generation projects.
- Income Tax Expense decreased $8 million primarily due to a decrease in pretax book income and state income taxes.

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Reconciliation of Nine Months Ended September 30, 2006 to Nine Months Ended September 30, 2007
Net Income
(in millions)

Nine Months Ended September 30, 2006		$ 96
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	(29)	
Other	(15)	
Total Change in Gross Margin		(44)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(17)	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	(1)	
Other Income	7	
Interest Expense	(8)	
Total Change in Operating Expenses and Other		(24)
Minority Interest Expense		(1)
Income Tax Expense		28
Nine Months Ended September 30, 2007		$ 55

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

Net Income decreased $41 million to $55 million in 2007. The key drivers of the decrease were a $44 million decrease in Gross Margin and a $24 million increase in Operating Expenses and Other, offset by a $28 million decrease in Income Tax Expense.

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

- Retail and Off-system Sales Margins decreased $29 million primarily due to a $24 million provision related to a SWEPCo Texas fuel reconciliation proceeding. See “SWEPCo Fuel Reconciliation – Texas” section of Note 3.
- Other revenues decreased $15 million primarily due to an $8 million decrease in gains on sales of emission allowances and a $7 million decrease in revenue from coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC, to outside parties. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

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

- Other Operation and Maintenance expenses increased $17 million primarily due to the following:
  - A $9 million increase in generation expenses from planned and forced outages at the Welsh, Dolet Hills, Flint Creek, Knox Lee and Pirkey Plants.
  - An $8 million increase in transmission expenses related to higher SPP administration fees and transmission services from other utilities.
  - A $6 million increase in distribution expenses including increased overhead line maintenance.

  These increases were partially offset by:
  - An $8 million decrease in expenses primarily resulting from decreased coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC, due to planned and forced outages at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation, a nonaffiliated entity.
- Other Income increased $7 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects.
- Interest Expense increased $8 million primarily due to $13 million of interest related to increased long-term debt partially offset by a $5 million increase in the debt component of AFUDC due to new generation projects.
- Income Tax Expense decreased $28 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

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

	Moody’s	**S&P**	**Fitch**
Senior Unsecured Debt	Baa1	BBB	A-

Cash Flow

Cash flows for the nine months ended September 30, 2007 and 2006 were as follows:

	2007	**2006**
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,618	$ 3,049
Cash Flows From (Used For):		
Operating Activities	180,146	242,721
Investing Activities	(353,001)	(186,631)

Financing Activities		172,089		(56,343)
Net Decrease in Cash and Cash Equivalents		(766)		(253)
Cash and Cash Equivalents at End of Period	$	1,852	$	2,796

Operating Activities

Net Cash Flows From Operating Activities were $180 million in 2007. SWEPCo produced Net Income of $55 million during the period and had noncash expense items of $103 million for Depreciation and Amortization and $24 million related to the Provision for Fuel Disallowance recorded as the result of an ALJ ruling in SWEPCo's Texas fuel reconciliation proceeding. 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 $48 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $37 million inflow from Margin Deposits was due to decreased trading-related deposits resulting from normal trading activities. The $27 million outflow from Fuel Over/Under Recovery, Net is due to under recovery of higher fuel costs.

Net Cash Flows From Operating Activities were $243 million in 2006. SWEPCo produced Net Income of $96 million during the period and had noncash expense items of $99 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $54 million inflow from Accounts Payable was the result of higher energy purchases. The $28 million outflow for Margin Deposits was due to increased trading-related deposits resulting from the amended SIA. In addition, the $64 million inflow related to Over/Under Fuel Recovery was primarily due to the new fuel surcharges effective December 2005 in SWEPCo's Arkansas service territory and in January 2006 in SWEPCo's Texas service territory. The $27 million outflow from Fuel, Materials and Supplies was the result of increased fuel purchases.

Investing Activities

Net Cash Flows Used For Investing Activities during 2007 and 2006 were $353 million and $187 million, respectively. The $353 million of cash flows for Construction Expenditures during 2007 were primarily related to new generation facilities. The cash flows during 2006 were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability as well as projects related to generation facilities. Based upon SWEPCo's current forecast, SWEPCo expects construction expenditures to be approximately $210 million for the remainder of 2007, excluding AFUDC.

Financing Activities

Net Cash Flows From Financing Activities were $172 million during 2007. SWEPCo issued $250 million of Senior Unsecured Notes and retired $90 million of First Mortgage Bonds. SWEPCo received a Capital Contribution from Parent of $55 million. SWEPCo also reduced its borrowings from the Utility Money Pool by $33 million.

Net Cash Flows Used for Financing Activities were $56 million during 2006. SWEPCo refinanced $82 million of Pollution Control Bonds. SWEPCo reduced its borrowings from the Utility Money Pool by $28 million and paid $30 million in common stock dividends.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2007 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	250,000	5.55	2017

Retirements

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Nonaffiliated	$	4,210	4.47	2011
Notes Payable – Nonaffiliated		4,000	6.36	2007
Notes Payable – Nonaffiliated		2,250	Variable	2008
First Mortgage Bonds		90,000	7.00	2007

Liquidity

SWEPCo has solid investment grade ratings, which provides ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, SWEPCo participates in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of SWEPCo's contractual obligations is included in its 2006 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above, Energy and Capacity Purchase Contracts, and contractual commitments related to the proposed Turk Plant. Effective January 1, 2007, SWEPCo transferred a significant amount of ERCOT energy marketing contracts to AEP Energy Partners (AEPEP), thereby decreasing its future obligations in Energy and Capacity Purchase Contracts. See "ERCOT Contracts Transferred to AEPEP" section of Note 1. SWEPCo has entered into additional contractual commitments related to the construction of the proposed Turk Plant announced in August 2006. See "Turk Plant" in the "Arkansas Rate Matters" section of Note 3.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, SWEPCo 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 pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2006 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees 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 SWEPCo's 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 SWEPCo.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2006 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.

Adoption of New Accounting Pronouncements

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section for a discussion of adoption of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. 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 SWEPCo.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in the condensed consolidated balance sheet as of September 30, 2007 and the reasons for changes in total MTM value as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2007
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 51,042	$ 75	$ 51,117
Noncurrent Assets	6,481	33	6,514
Total MTM Derivative Contract Assets	57,523	108	57,631
Current Liabilities	(38,334)	(11)	(38,345)
Noncurrent Liabilities	(6,729)	-	(6,729)
Total MTM Derivative Contract Liabilities	(45,063)	(11)	(45,074)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 12,460	$ 97	$ 12,557

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2007
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$	20,166
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(3,501)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		1,201
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(5,406)
Total MTM Risk Management Contract Net Assets		12,460
Net Cash Flow Hedge Contracts		97
Total MTM Risk Management Contract Net Assets at September 30, 2007	$	12,557

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

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

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

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

The following table presents:

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of September 30, 2007
(in thousands)

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ (3,730)	$ 1,544	$ (237)	$ (8)	$ -	$ -	$ (2,431)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	10,247	5,930	(728)	-	-	-	15,449
Prices Based on Models and Other Valuation Methods (b)	(772)	(1,286)	1,502	(2)	-	-	(558)
Total	$ 5,745	$ 6,188	$ 537	$ (10)	$ -	$ -	$ 12,460

(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 independent information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market. Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available including values determinable by other third party transactions.

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

SWEPCo is exposed to market fluctuations in energy commodity prices impacting power operations. Management monitors these risks on future operations and may use various commodity derivative instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. Management does not hedge all commodity price risk.

Management uses interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. Management does not hedge all interest rate risk.

Management uses foreign currency derivatives to lock in prices on certain transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedge strategies. Management does not hedge all foreign currency.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on the Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2006 to September 30, 2007. 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, 2007
(in thousands)

	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2006	$ (6,435)	$ 25	$ (6,410)
Changes in Fair Value	(1,019)	589	(430)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	598	-	598
Ending Balance in AOCI September 30, 2007	$ (6,856)	$ 614	$ (6,242)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $829 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure 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, 2007, a near term typical change in commodity prices is not expected to have a material effect on 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, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$ 26	$ 245	$ 92	$ 23	$ 447	$ 2,171	$ 794	$ 68

VaR Associated with Debt Outstanding

Management also utilizes 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 exposure to interest rates primarily related to long-term debt with fixed interest rates was $41 million and $25 million at September 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended 2007	Three Months Ended 2006	Nine Months Ended 2007	Nine Months Ended 2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 445,169	$ 440,542	$ 1,101,703	$ 1,084,185
Sales to AEP Affiliates	2,839	14,692	35,491	34,871
Other	502	1,466	1,437	2,260
TOTAL	448,510	456,700	1,138,631	1,121,316
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	141,837	158,992	379,818	367,924
Purchased Electricity for Resale	73,438	61,816	182,806	135,918
Purchased Electricity from AEP Affiliates	22,282	18,140	61,284	58,303
Other Operation	59,759	55,173	163,746	158,089
Maintenance	23,205	21,120	79,265	68,008
Depreciation and Amortization	34,605	33,079	103,395	98,655
Taxes Other Than Income Taxes	16,767	17,107	50,298	49,254
TOTAL	371,893	365,427	1,020,612	936,151
OPERATING INCOME	76,617	91,273	118,019	185,165
Other Income (Expense):				
Interest Income	518	822	1,999	2,277
Allowance for Equity Funds Used During Construction	3,681	287	7,634	400
Interest Expense	(15,966)	(13,844)	(48,691)	(40,688)
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST EXPENSE	64,850	78,538	78,961	147,154
Income Tax Expense	19,811	27,873	20,879	49,187
Minority Interest Expense	919	959	2,733	2,077
NET INCOME	44,120	49,706	55,349	95,890
Preferred Stock Dividend Requirements	58	57	172	172
EARNINGS APPLICABLE TO COMMON STOCK	$ 44,062	$ 49,649	$ 55,177	$ 95,718

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 135,660	$ 245,003	$ 407,844	$ (6,129)	$ 782,378
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(172)		(172)
TOTAL					752,206
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $817				(1,516)	(1,516)
NET INCOME			95,890		95,890
TOTAL COMPREHENSIVE INCOME					94,374
SEPTEMBER 30, 2006	$ 135,660	$ 245,003	$ 473,562	$ (7,645)	$ 846,580
DECEMBER 31, 2006	$ 135,660	$ 245,003	$ 459,338	$ (18,799)	$ 821,202
FIN 48 Adoption, Net of Tax			(1,642)		(1,642)
Capital Contribution from Parent		55,000			55,000
Preferred Stock Dividends			(172)		(172)
TOTAL					874,388
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $90				168	168
NET INCOME			55,349		55,349
TOTAL COMPREHENSIVE INCOME					55,517
SEPTEMBER 30, 2007	$ 135,660	$ 300,003	$ 512,873	$ (18,631)	$ 929,905

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2007 and December 31, 2006
(in thousands)
(Unaudited)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,852	$ 2,618
Accounts Receivable:		
Customers	50,382	88,245
Affiliated Companies	47,982	59,679
Miscellaneous	10,057	8,595
Allowance for Uncollectible Accounts	(24)	(130)
Total Accounts Receivable	108,397	156,389
Fuel	78,295	69,426
Materials and Supplies	48,716	46,001
Risk Management Assets	51,117	120,036
Regulatory Asset for Under-Recovered Fuel Costs	7,300	-
Margin Deposits	4,199	41,579
Prepayments and Other	19,925	18,256
TOTAL	319,801	454,305
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,650,597	1,576,200
Transmission	719,033	668,008
Distribution	1,298,926	1,228,948
Other	627,145	595,429
Construction Work in Progress	412,704	259,662
Total	4,708,405	4,328,247
Accumulated Depreciation and Amortization	1,910,411	1,834,145
TOTAL - NET	2,797,994	2,494,102
OTHER NONCURRENT ASSETS		
Regulatory Assets	131,264	156,420
Long-term Risk Management Assets	6,514	20,531
Deferred Charges and Other	75,529	65,610
TOTAL	213,307	242,561
TOTAL ASSETS	$ 3,331,102	$ 3,190,968

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 155,869	$ 188,965
Accounts Payable:		
General	136,071	140,424
Affiliated Companies	65,692	68,680
Short-term Debt – Nonaffiliated	25,897	17,143
Long-term Debt Due Within One Year – Nonaffiliated	6,655	102,312
Risk Management Liabilities	38,345	109,578
Customer Deposits	39,225	48,277
Accrued Taxes	54,784	31,591
Regulatory Liability for Over-Recovered Fuel Costs	30,495	26,012
Other	67,680	85,086
TOTAL	620,713	818,068
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	818,429	576,694
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	6,729	14,083
Deferred Income Taxes	354,175	374,548
Regulatory Liabilities and Deferred Investment Tax Credits	330,070	346,774
Deferred Credits and Other	214,505	183,087
TOTAL	1,773,908	1,545,186
TOTAL LIABILITIES	2,394,621	2,363,254
Minority Interest	1,879	1,815
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	300,003	245,003
Retained Earnings	512,873	459,338
Accumulated Other Comprehensive Income (Loss)	(18,631)	(18,799)
TOTAL	929,905	821,202
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,331,102	$ 3,190,968

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(in thousands)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 55,349	$ 95,890
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	103,395	98,655
Deferred Income Taxes	(17,863)	(24,642)
Provision for Fuel Disallowance	24,074	-
Mark-to-Market of Risk Management Contracts	7,706	10,870
Deferred Property Taxes	(9,172)	(9,438)
Change in Other Noncurrent Assets	2,536	20,733
Change in Other Noncurrent Liabilities	(7,134)	(33,256)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	47,992	(9,872)
Fuel, Materials and Supplies	(11,572)	(26,739)
Margin Deposits	37,380	(28,492)
Accounts Payable	(21,603)	54,264
Accrued Taxes, Net	25,556	45,514
Fuel Over/Under Recovery, Net	(26,891)	63,862
Other Current Assets	(687)	2,635
Other Current Liabilities	(28,920)	(17,263)
Net Cash Flows From Operating Activities	180,146	242,721
INVESTING ACTIVITIES		
Construction Expenditures	(353,107)	(179,117)
Change in Advances to Affiliates, Net	-	(7,018)
Other	106	(496)
Net Cash Flows Used For Investing Activities	(353,001)	(186,631)
FINANCING ACTIVITIES		
Capital Contribution from Parent	55,000	-
Issuance of Long-term Debt – Nonaffiliated	247,496	80,593
Change in Short-term Debt, Net – Nonaffiliated	8,754	14,282
Change in Advances from Affiliates, Net	(33,096)	(28,210)
Retirement of Long-term Debt – Nonaffiliated	(100,460)	(88,989)
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(5,433)	(3,845)
Dividends Paid on Common Stock	-	(30,000)
Dividends Paid on Cumulative Preferred Stock	(172)	(172)
Net Cash Flows From (Used For) Financing Activities	172,089	(56,343)
Net Decrease in Cash and Cash Equivalents	(766)	(253)
Cash and Cash Equivalents at Beginning of Period	2,618	3,049
Cash and Cash Equivalents at End of Period	$ 1,852	$ 2,796
SUPPLEMENTARY INFORMATION		

Cash Paid for Interest, Net of Capitalized Amounts	$ 44,662	$ 37,372
Net Cash Paid for Income Taxes	37,479	53,509
Noncash Acquisitions Under Capital Leases	19,567	17,110
Construction Expenditures Included in Accounts Payable at September 30,	41,978	8,924

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
2.	New Accounting Pronouncements and Extraordinary Item	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
3.	Rate Matters	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
4.	Commitments, Guarantees and Contingencies	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
5.	Acquisition	CSPCo
6.	Benefit Plans	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
7.	Business Segments	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
8.	Income Taxes	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
9.	Financing Activities	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed 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 SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual 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 the results of operations, financial position and cash flows for the interim periods for each Registrant Subsidiary. The results of operations for the nine months ended September 30, 2007 are not necessarily indicative of results that may be expected for the year ending December 31, 2007. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2006 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2006 as filed with the SEC on February 28, 2007.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

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

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

Inventory

Fossil fuel inventories are carried at average cost for APCo, I&M, and SWEPCo. OPCo and CSPCo value fossil fuel inventories at the lower of average cost or market. PSO carries fossil fuel inventories utilizing a LIFO method. Excess of replacement or current cost over stated LIFO value for PSO was $9 million and $4 million as of September 30, 2007 and December 31, 2006, respectively. The materials and supplies inventories are carried at average cost.

Revenue Recognition

Traditional Electricity Supply and Delivery Activities

Registrant Subsidiaries recognize revenues from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. Registrant Subsidiaries recognize the revenues in the financial statements upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory, and the AEP East companies purchase power back from the same RTO to supply power to their respective loads. These power sales and purchases are reported on a net basis as revenues in the financial statements. Other RTOs in which the Registrant Subsidiaries operate do not function in the same manner as PJM. They function as balancing organizations and not as an exchange.

Physical energy purchases including those from all RTOs that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale in the financial statements.

In general, Registrant Subsidiaries record expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Beginning in July 2004, as a result of the sale of generation assets in AEP's west zone, AEP's west zone is short capacity and must purchase physical power to supply retail and wholesale customers. For power purchased under derivative contracts in AEP's west zone where the AEP West companies are short capacity, they recognize as revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period before settlement. If the contract results in the physical delivery of power from a RTO or any other counterparty, the Registrant Subsidiaries reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Energy for Resale. If the contract does not result in physical delivery, the Registrant Subsidiaries reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as revenues in the financial statements on a net basis.

Energy Marketing and Risk Management Activities

All of the Registrant Subsidiaries engage in wholesale electricity, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets. Registrant Subsidiaries' activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. The Registrant Subsidiaries engage in certain energy marketing and risk management transactions with RTOs.

Registrant Subsidiaries recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. Registrant Subsidiaries use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow or fair value hedge relationship, or as a normal purchase or sale. The unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in revenues in the financial statements on a net basis. In jurisdictions subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain wholesale marketing and risk management transactions are designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in revenues in the financial statements in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income (Loss) and, depending upon the specific nature of the risk being hedged, subsequently reclassified into revenues or expenses in the financial statements when the forecasted transaction is realized and affects earnings. The ineffective portion of the gain or loss is recognized in revenues in the financial statements immediately, except in those jurisdictions subject to cost-based regulation. In those regulated jurisdictions the Registrant Subsidiaries defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for Registrant Subsidiaries as of September 30, 2007 and December 31, 2006 is shown in the following table:

Components	September 30, 2007	December 31, 2006
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (3,547)	$ (2,547)
CSPCo	1,113	3,398
I&M	(10,709)	(8,962)
OPCo	3,776	7,262
PSO	(933)	(1,070)
SWEPCo	(6,242)	(6,410)
SFAS 158 Costs:		
APCo	$ (40,999)	$ (52,244)
CSPCo	(25,386)	(25,386)
I&M	(6,089)	(6,089)
OPCo	(64,025)	(64,025)
SWEPCo	(12,389)	(12,389)

As shown in the following table, during the next twelve months, the Registrant Subsidiaries expect to reclassify net gains and losses from cash flow hedges in AOCI to Net Income at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from AOCI to Net Income can differ as a result of market fluctuations. Also shown in the following table is the maximum length of time that the Registrant Subsidiary's exposure to variability in future cash flows is hedged with contracts designated as cash flow hedges.

	September 30, 2007 (in thousands)	(in months)
APCo	$ 740	20
CSPCo	643	20
I&M	(390)	20
OPCo	1,576	20
PSO	(183)	-
SWEPCo	(829)	33

Related Party Transactions

Lawrenceburg Unit Power Agreement (UPA) between CSPCo and AEGCo

In March 2007, CSPCo and AEGCo entered into a 10-year UPA for the entire output from the Lawrenceburg Plant effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional 2-year period. I&M operates the plant under an agreement with AEGCo.

Under the UPA, CSPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

CSPCo paid AEGCo $41.9 million and $57.8 million for the three and nine months ended September 30, 2007, respectively. On its 2007 Condensed Consolidated Statement of Income, CSPCo recorded these purchases in Other Operation expense for the capacity and depreciation portion, and in Purchased Electricity from AEP Affiliates for the variable cost portion.

ERCOT Contracts Transferred to AEPEP

Effective January 1, 2007, PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEPEP and entered into intercompany financial and physical purchase and sale agreements with AEPEP. This was done to lock in PSO and SWEPCo's margins on ERCOT trading and marketing contracts and to transfer the future associated commodity price and credit risk to AEPEP. The contracts will mature over the next three years.

PSO and SWEPCo have historically presented third party ERCOT trading and marketing activity on a net basis in Revenues - Electric Generation, Transmission and Distribution. The applicable ERCOT third party trading and marketing contracts that were not transferred to AEPEP will remain until maturity on PSO and SWEPCo and will be presented on a net basis in Sales to AEP Affiliates on PSO's and SWEPCo's Statements of Income.

The following table indicates the sales to AEPEP and the amounts reclassified from third party to affiliate:

	For the Three Months Ended September 30, 2007		
Company	Net Settlement With AEPEP	Third Party Amounts Reclassified to Affiliate (in thousands)	Net Amount included in Sales to AEP Affiliates
PSO	$ 61,702	$ (67,759)	$ 6,057
SWEPCo	77,784	(84,920)	7,136

	For the Nine Months Ended September 30, 2007		
Company	Net Settlement With AEPEP	Third Party Amounts Reclassified to Affiliate (in thousands)	Net Amount included in Sales to AEP Affiliates
PSO	$ 138,145	$ (133,903)	$ (4,242)
SWEPCo	171,338	(166,339)	(4,999)

The following table indicates the affiliated portion of risk management assets and liabilities reflected on PSO's and SWEPCo's balance sheets associated with these contracts:

	As of September 30, 2007	
	PSO	SWEPCo
Current	(in thousands)	
Risk Management Assets	$ 19,116	$ 22,546
Risk Management Liabilities	(520)	(614)
Noncurrent		
Long-term Risk Management Assets	$ 2,510	$ 2,960
Long-term Risk Management Liabilities	-	-

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo's and approximately 3% of TNC's businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007 and were recorded at net book value of $11.6 million. The Arkansas Public Service Commission's approval requires SWEPCo to amend its fuel recovery tariff so that Arkansas customers do not pay the incremental cost of serving the additional load.

Reclassifications

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

On their statements of income, the Registrant Subsidiaries reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. The following table shows the credits reclassified by the Registrant Subsidiaries in 2006:

Company	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006
	(in thousands)	
APCo	$ 110	$ 708
I&M	5,509	17,216

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of new pronouncements issued or implemented in 2007 and standards issued but not implemented that management has determined relate to the Registrant Subsidiaries' operations.

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. Management expects that the adoption of this standard will impact MTM valuations of certain contracts. Management is evaluating the effect of the adoption of SFAS 157 on the Registrant Subsidiaries' results of operations and financial condition. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. Although management has not completed its analysis, management expects this cumulative effect adjustment will have an immaterial impact on the Registrant Subsidiaries' financial statements. The Registrant Subsidiaries will adopt SFAS 157 effective January 1, 2008.

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

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

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. If the Registrant Subsidiaries elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. The Registrant Subsidiaries will adopt SFAS 159 effective January 1, 2008. Although management has not completed its analysis, management expects the adoption of this standard to have an immaterial impact on the financial statements.

EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

EITF 06-11 will be applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years beginning after September 15, 2007. Management expects that the adoption of this standard will have an immaterial impact on the financial statements. The Registrant Subsidiaries will adopt EITF 06-11 effective January 1, 2008.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48" (FIN 48)

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." 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. The Registrant Subsidiaries adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable (favorable) adjustment to retained earnings as follows:

Company	(in thousands)
APCo	$ 2,685
CSPCo	3,022
I&M	(327)
OPCo	5,380
PSO	386
SWEPCo	1,642

FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

FIN 39-1 is effective for fiscal years beginning after November 15, 2007. Management expects this standard to change the method of netting certain balance sheet amounts but is unable to quantify the effect. It requires retrospective application as a change in accounting principle for all periods presented. The Registrant Subsidiaries will adopt FIN 39-1 effective January 1, 2008.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including business combinations, revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, leases, insurance, subsequent events and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

EXTRAORDINARY ITEM

APCo recorded an extraordinary loss of $118 million ($79 million, net of tax) during the second quarter of 2007 for the establishment of regulatory assets and liabilities related to the Virginia generation operations. In 2000, APCo discontinued SFAS 71 regulatory accounting for the Virginia jurisdiction due to the passage of legislation for customer choice and deregulation. In April 2007, Virginia passed legislation to establish electric regulation again. See "Virginia Restructuring" in Note 3.

3. RATE MATTERS

As discussed in the 2006 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2006 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, cash flows and possibly financial condition. The following discusses ratemaking developments in 2007 and updates the 2006 Annual Report.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans – Affecting CSPCo and OPCo

Ending December 31, 2008, the approved three-year RSPs provide CSPCo and OPCo increases in their generation rates by 3% and 7%, respectively, effective January 1 each year and allow possible additional annual generation rate increases of up to an average of 4% per year to recover governmentally-mandated costs. In January 2007, CSPCo and OPCo filed with the PUCO pursuant to the average 4% generation rate provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover new governmentally-mandated costs. CSPCo and OPCo implemented these proposed increases in May 2007 subject to refund. In October 2007, the PUCO issued an order in the average 4% proceeding which granted CSPCo and OPCo an annual generation rate increase through December 2008 of $19 million and $4 million, respectively. In September 2007, CSPCo and OPCo recorded a provision for refund to adjust revenues consistent with the rate revenues granted by the PUCO. Management expects that the average 4% rider will be reduced to implement the required refunds, while OPCo would implement a credit to customers' bills. CSPCo and OPCo intend to seek rehearing of the PUCO decision.

In October 2007, CSPCo and OPCo made a new filing with the PUCO pursuant to the average 4% generation rate provision of their RSPs for an additional increase in their annual generation rates effective January 2008 of $35 million and $12 million, respectively, to recover governmentally-mandated costs and increased costs related to marginal-loss pricing. CSPCo and OPCo will implement these proposed increases in January 2008 subject to refund until the PUCO issues a final order in the matter. Management is unable to predict the outcome of this filing and its impact on future results of operations and cash flows.

In March 2007, CSPCo filed an application under the average 4% generation rate provision of their RSP to adjust the Power Acquisition Rider (PAR) related to CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio. The PAR was increased to recover the cost of a new purchase power market contract to serve the load for that service territory. The PUCO approved the requested increase in the PAR, which is expected to increase CSPCo's revenues by $22 million and $38 million for 2007 and 2008, respectively.

In March 2007, CSPCo and OPCo filed a settlement agreement at the PUCO resolving the Ohio Supreme Court's remand of the PUCO’s RSP order. The settling parties agreed to have CSPCo and OPCo take bids for Renewable Energy Certificates (RECs). CSPCo and OPCo will give customers the option to pay a generation rate premium that would encourage the development of renewable energy sources by reimbursing CSPCo and OPCo for the cost of the RECs and the administrative costs of the program. The Office of Consumers’ Counsel, the Ohio Partners for Affordable Energy, the Ohio Energy Group and the PUCO staff supported this settlement agreement. In May 2007, the PUCO adopted the settlement agreement in its entirety.

Customer Choice Deferrals – Affecting CSPCo and OPCo

CSPCo’s and OPCo’s restructuring settlement agreement approved by the PUCO in 2000, allows CSPCo and OPCo to establish regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general base rate filing which changes distribution rates. Through September 30, 2007, CSPCo and OPCo incurred $53 million and $54 million, respectively, of such costs and established regulatory assets of $27 million each for the future recovery of such costs. CSPCo and OPCo also have the right to recover $6 million and $7 million, respectively, of equity carrying costs in addition to these regulatory assets. In 2007, CSPCo and OPCo incurred $3 million and $4 million, respectively, of such costs and established regulatory assets of $2 million each for such costs. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure to recover such costs would have an adverse effect on results of operations and cash flows.

Ohio IGCC Plant – CSPCo and OPCo

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the average 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo 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 a period of no more than twelve months effective July 1, 2006. Through September 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. As of September 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered.

The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs collected for pre-construction costs, associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Ohio Industrial Energy Users, Ohio Consumers’ Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO’s order in the IGCC proceeding. The Ohio Supreme Court heard oral arguments for these appeals in October 2007. Management believes that the PUCO's authorization to begin collection of Phase 1 rates is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase 1 cost-related recoveries.

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant have escalated to $2.2 billion. CSPCo and OPCo may need to request an extension to the 5-year start of construction requirement if the commencement of construction is delayed beyond 2011.

Distribution Reliability Plan – Affecting CSPCo and OPCo

In the fourth quarter of 2006, as directed by the PUCO, CSPCo and OPCo filed a proposed enhanced reliability plan. The plan contemplated CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen-month period beginning July 2007.

In April 2007, CSPCo and OPCo filed a joint motion with the PUCO staff, the Ohio Consumers' Counsel, the Appalachian People's Action Coalition, the Ohio Partners for Affordable Energy and the Ohio Manufacturers Association to withdraw the proposed enhanced reliability plan. The motion was granted in May 2007. CSPCo and OPCo do not intend to implement the enhanced reliability plan without recovery of any incremental costs.

Ormet – Affecting CSPCo and OPCo

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load in accordance with a settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties that was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH to be paid by Ormet for power and a PUCO-approved market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is insufficient, an increase in RSP generation rates under the additional average 4% generation rate provision of the RSPs.

In December 2006, CSPCo and OPCo submitted a market price of $47.69 per MWH for 2007, which was approved by the PUCO in June 2007. CSPCo and OPCo have each amortized $5 million of their Ohio Franchise Tax phase-out tax regulatory liability to income through September 30, 2007. If the PUCO approves a lower market price in 2008, it could have an adverse effect on future results of operations and cash flows. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo off-system sales margins.

Texas Rate Matters

SWEPCo Fuel Reconciliation – Texas – Affecting SWEPCo

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations for the three-year reconciliation period ended December 31, 2005. SWEPCo sought, in the proceedings, to include under-recoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The PUCT staff and intervenor disallowances ranged from $10 million to $28 million. In June 2007, an ALJ issued a proposal for decision recommending a $17 million disallowance. Results of operations for the second quarter of 2007 were adversely affected by $25 million to reflect the ALJ's decision that apply to the reconciliation period and subsequent periods through 2007. In August 2007, the PUCT issued a final order affirming the ALJ report. In September 2007, SWEPCo filed a motion for rehearing. In October 2007, the PUCT granted SWEPCo's motion for rehearing. The PUCT reversed its prior determination that SO_2 allowance gains should be credited through the fuel clause. However, the PUCT ruled SWEPCo was obligated to credit the fuel clause with gains from sales of emissions allowances through June 30, 2006. This change affects allowances sold after June 2006 and its impact will be considered in the fourth quarter of 2007. In October 2007, the PUCT issued a revised order which should allow SWEPCo to reverse $7 million of its earlier provision in the fourth quarter of 2007. SWEPCO is considering whether to challenge other parts of the order.

Stall Unit – Affecting SWEPCo

See "Stall Unit" section within Louisiana Rate Matters for disclosure.

Turk Plant – Affecting SWEPCo

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

Virginia Rate Matters

Virginia Restructuring – Affecting APCo

In April 2004, Virginia enacted legislation that amended the Virginia Electric Utility Restructuring Act extending the transition period to market rates for the generation and supply of electricity, including the extension of capped rates, through December 31, 2010. The legislation provided APCo with specified cost recovery opportunities during the extended capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain unrecovered incremental environmental and reliability costs incurred on and after July 1, 2004. Under the amended restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to have the opportunity to recover incremental E&R costs.

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation of electric utilities' generation and supply rates. These amendments shorten the transition period by two years (from 2010 to 2008) after which rates for retail generation and supply will return to cost-based regulation in lieu of market-based rates. The legislation provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investments, (b) demand side management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments; significant return on equity enhancements for investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a floor on the allowed return on equity based on the average earned return on equities' of regional vertically integrated electric utilities. Effective July 1, 2007, the amendments allow utilities to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. The new re-regulation legislation should result in significant positive effects on APCo's future earnings and cash flows from the mandated enhanced future returns on equity, the reduction of regulatory lag from the opportunities to adjust base rates on a biennial basis and the new opportunities to request timely recovery of certain new costs not included in base rates.

With the new re-regulation legislation, APCo's generation business again met the criteria for application of regulatory accounting principles under SFAS 71. The extraordinary pretax reduction in APCo's earnings and shareholder's equity from reapplication of SFAS 71 regulatory accounting of $118 million ($79 million, net of tax) was recorded in the second quarter of 2007. This extraordinary net loss relates to the reestablishment of $139 million in net generation-related customer-provided removal costs as a regulatory liability, offset by the restoration of $21 million of deferred state income taxes as a regulatory asset. In addition, APCo established a regulatory asset of $17 million for qualifying SFAS 158 pension costs of the generation operations that, for ratemaking purposes, are deferred for future recovery under the new re-regulation legislation. AOCI and Deferred Income Taxes increased by $11 million and $6 million, respectively.

Virginia Base Rate Case – Affecting APCo

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including the cost of its investment in environmental equipment and a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to its active fuel clause. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which was estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. In May 2006, the Virginia SCC issued an order placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund.

In May 2007, the Virginia SCC issued a final order approving an overall annual base rate increase of $24 million effective as of October 2006 and approving a return on equity of 10.0%. As a result of the final order, APCo's second quarter pretax earnings decreased by approximately $3 million due to a decrease in revenues of $42 million net of a recorded provision for refund and related interest offset by (a) a $15 million net effect from the deferral of unrecovered incremental E&R costs incurred from October 1, 2006 through June 30, 2007 to be collected in a future E&R filing, (b) a $9 million net deferral of ARO costs to be recovered over 10 years and (c) a $15 million retroactive decrease in depreciation expense. As a result of the Virginia SCC decision to limit the recovery of incremental E&R costs through the new base rates, APCo will continue to defer for future recovery unrecovered incremental E&R costs incurred through 2008 utilizing the E&R surcharge mechanism. APCo completed the $127 million refund in August 2007.

Virginia E&R Costs Recovery Filing – Affecting APCo

In July 2007, APCo filed a request with the Virginia SCC seeking recovery over the twelve months beginning December 1, 2007 of approximately $60 million of unrecovered incremental E&R costs inclusive of carrying costs thereon incurred from October 1, 2005 through September 30, 2006. In August 2007, the Virginia SCC issued a scheduling order to begin the proceeding before a hearing examiner on November 5, 2007. In October 2007, the Virginia SCC staff and the Attorney General both filed testimony recommending that APCo recover $49 million of its $60 million of requested E&R costs. The two differences between APCo's request and the Virginia SCC staff and the Attorney General's recommendations relate to the recovery of carrying costs on the unrecovered incremental E&R costs and the appropriate return on equity rate. APCo intends to file in 2008 for recovery of additional incurred incremental E&R costs recorded and deferred after September 30, 2006.

APCo is currently recovering $21 million of incurred E&R costs through the initial E&R surcharge that will expire on November 30, 2007. Through September 30, 2007, APCo deferred $70 million in incremental E&R costs to be recovered in the current and future E&R filings. APCo has not recognized $15 million of equity carrying charges, which are recognizable when collected. The $70 million regulatory asset does not include carrying costs on the unrecovered incremental E&R costs and is based on a return on equity rate which approximates the Virginia SCC staff and Attorney General's recommendations. As a result, if APCo is awarded only $49 million for the E&R costs incurred for the twelve months ended September 30, 2006 as recommended by the Virginia SCC staff and the Attorney General, it will not have to reverse any of its regulatory asset deferrals.

Virginia Fuel Clause Filing – Affecting APCo

In July 2007, APCo filed an application with the Virginia SCC to seek an annualized increase, effective September 1, 2007, of $33 million for fuel costs and a sharing of the benefits of off-system sales between APCo and its customers. This filing was made in compliance with the minimum 25% retention of off-system sales margins provision of the new re-regulation legislation which is effective with the first fuel clause filing after July 1,

2007. This sharing requirement in the new law also includes a true-up to actual off-system sales margins. In addition, APCo requested authorization to defer for future recovery the difference between off-system sales margins credited to customers at 100% of the ordered amount through the current base rate margin rider and 75% of actual off-system sales margins as provided in the new law from July 1, 2007 until the new fuel rate becomes effective.

In August 2007, the Virginia SCC issued a scheduling order that implemented APCo's proposed termination of its base rate off-system sales margin rider on an interim basis, subject to refund, on September 1, 2007. The order also implemented APCo's proposed new fuel factor on an interim basis, effective September 1, 2007, which includes a credit for the sharing of 75% of off-system sales margins with customers in compliance with the new law. In October 2007, APCo, the Virginia SCC staff and certain intervenors filed memorandums addressing legal issues identified by the Virginia SCC regarding the appropriateness of the timing of the implementation of the new expanded fuel factor and off-system sales margins sharing with customers. Hearings are scheduled for November 2007. In October 2007, the Virginia SCC staff submitted testimony stating off-system sales margin sharing for July and August 2007 should be denied. In addition, the Virginia SCC staff asserted that no language exists in the statute requiring implementation of off-system sales margin sharing any earlier than 2011. Future results of operations and cash flows could be adversely affected if the Virginia SCC delays the effective date of the new expanded fuel clause beyond APCo's filed request.

West Virginia IGCC Plant – Affecting APCo

In July 2007, APCo filed a request with the Virginia SCC to recover, over the twelve months beginning January 1, 2009, a return on projected construction work in progress including development, design and planning costs from July 1, 2007 through December 31, 2009 estimated to be $45 million associated with the proposed 629 MW IGCC plant to be constructed in West Virginia for an estimated cost of $2.2 billion. APCo is requesting authorization to defer a return on actual pre-construction costs incurred beginning July 1, 2007 until such costs are recovered, starting January 1, 2009 in accordance with the new re-regulation legislation. The new re-regulation legislation provides for full recovery of all costs plus return on equity incentives for such new capacity once the plant is placed in service. See "West Virginia IGCC Plant" section within West Virginia Rate Matters.

West Virginia Rate Matters

APCo Expanded Net Energy Cost (ENEC) Filing – Affecting APCo

In April 2007, the WVPSC issued an order establishing an investigation and hearing concerning APCo's and WPCo's 2007 ENEC compliance filing. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits and other energy/transmission items. In the March 2007 ENEC joint filing, APCo filed for an increase of approximately $91 million including a $65 million increase in ENEC and a $26 million increase in construction cost surcharges to become effective July 1, 2007. In June 2007, the WVPSC issued an order approving, without modification, a joint stipulation and agreement for settlement reached among the parties. The settlement agreement provided for an increase in annual non-base revenues of approximately $77 million effective July 1, 2007. This annual revenue increase primarily includes $50 million of ENEC and $26 million of construction cost surcharges. The ENEC portion of the increase is subject to a true-up, which should avoid an earnings affect from an under-recovery of ENEC costs if they exceed the $50 million.

West Virginia IGCC Plant – Affecting APCo

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity (CCN) to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, WV.

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both the ongoing finance costs of the project during the construction period as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. If APCo receives all necessary approvals, the plant could be completed as early as mid-2012 and currently is expected to cost an estimated $2.2 billion**.** In July 2007, the WVPSC staff and intervenors filed to delay the procedural schedule by 90 days. APCo supported the changes to the procedural schedule. The statutory decision deadline was revised to March 2008. In July 2007, the WVPSC approved the revised procedural schedule. Through September 30, 2007, APCo deferred pre-construction IGCC costs totaling $11 million. If the plant is not built and these costs are not recoverable, future results of operations and cash flows would be adversely affected.

Indiana Rate Matters

Indiana Depreciation Study Filing – Affecting I&M

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counsel (OUCC) that would provide direct benefits to I&M's customers if new lower book depreciation rates were approved by the IURC. The direct benefits would include a $5 million credit to fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement were to be approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended and parties to the settlement agreed to a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately $69 million 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. In June 2007, the IURC approved the settlement agreement, but modified the effective date of the new book depreciation rates to the date I&M filed a general rate petition. On June 19, 2007, I&M and the OUCC notified the IURC that the parties would accept the modification to the settlement agreement. Therefore, I&M filed its rate petition and reduced its book depreciation rates as agreed upon in the settlement agreement.

The settlement agreement modification reduced book depreciation rates, which will result in an increase of $37 million in pretax earnings for the period June 19, 2007 to December 31, 2007. The $37 million increase is partially offset by a $5 million regulatory liability, recorded in June 2007, to provide for the agreed-upon fuel credit. I&M's approved book depreciation rates are subject to further review in the general rate case. Management expects new base rates will become effective in early 2009.

Indiana Rate Filing – Affecting I&M

In June 2007, I&M filed a rate notification petition with the IURC regarding its intent to file for a base rate increase with a proposed test year ended September 30, 2007. The petition indicated, among other things, the filing would include a request to implement rate tracker mechanisms for certain variable components of the cost of service including PJM RTO costs, reliability enhancement costs, demand side management/energy efficiency program costs, off-system sales margins, and net environmental compliance costs. This filing will also reflect the revenue requirement reduction associated with an annual reduction in book depreciation expense. In August 2007, the IURC approved the September 30, 2007 test year and the inclusion of the above trackers in the rate filing with a rate case to be filed no later than January 31, 2008. Management expects to file the case in early 2008 with a decision expected in early 2009.

Indiana Rate Cap – Affecting I&M

Effective July 1, 2007, I&M's rate cap ended for both base and fuel rates in Indiana. As a result, I&M's fuel factor in Indiana increased with the July 2007 billing month to recover the projected cost of fuel. I&M will resume deferring through revenues any under/over-recovered fuel costs for future recovery/refund. Under the capped rates, I&M was unable to recover $44 million of fuel costs since 2004 of which $7 million adversely impacted 2007 pretax earnings through June 30, 2007. Future results of operations should no longer be adversely impacted by fuel costs.

Michigan Rate Matters

Michigan Depreciation Study Filing– Affecting I&M

In December 2006, I&M filed a depreciation study in Michigan seeking to reduce its book depreciation rates. In September 2007, the Michigan Public Service Commission (MPSC) approved a settlement agreement authorizing I&M to implement new book depreciation rates. Based on the depreciation study included in the settlement, I&M agreed to decrease pretax annual depreciation expense, on a Michigan jurisdictional basis, by approximately $10 million. This settlement reflects 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 retail customers' electric service rates. In addition and as a result of the new MPSC-approved rates, I&M will decrease pretax annual depreciation expense, on a FERC jurisdictional basis, by approximately $11 million which will reduce wholesale rates for customers representing approximately half the load beginning in November 2007 and reduce wholesale rates for the remaining customers in June 2008.

Oklahoma Rate Matters

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

In 2002, PSO under-recovered $44 million of purchased power costs through its fuel clause resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. The Oklahoma Industrial Energy Customers (OIEC) filed a motion asking the OCC to reconsider its order on the jurisdictional issue. The OCC stayed its final order regarding the FERC jurisdictional issue. In October 2007, the OCC lifted its stay stating the OCC does not have jurisdiction regarding the allocation methodology for off-system sales margins.

The OIEC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins to 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. However, to date, there has been no claim asserted at the FERC that the AEP System deviated from the FERC-approved allocation methodologies, but even if one were asserted, management believes that its allocation of off-system sales margins under the FERC-approved SIA agreement was consistent with that agreement. In October 2007, the OCC directed OCC Staff to file a complaint at FERC concerning this matter.

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 PSO failed to achieve that he alleges existed during the year. In August 2007, an ALJ issued a report recommending that PSO's fuel procurement practices were prudent and no adjustments were warranted. No parties appealed the recommendation. In October 2007, the OCC issued a final order adopting the ALJ's report.

In February 2006, the OCC enacted a rule, 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 periodic reviews. PSO filed its testimony in June 2007 covering the year 2005. The OCC Staff and intervenors filed testimony in September 2007.

In May 2007, PSO submitted a filing to the OCC to adjust its fuel/purchase power rates. In the filing, PSO netted the $42 million of under-recovered pre-2002 reallocated purchased power costs against their $48 million over-recovered fuel balance as of April 30, 2007. The $6 million net over-recovered fuel/purchased power cost deferral balance will be refunded over the twelve-month period beginning June 2007. However, in August 2007, the OIEC filed a motion asking the OCC to order a refund of the $42 million pre-2002 reallocated purchased power costs netted against the current over-recovered fuel balance. In October 2007, the OCC denied the OIEC's request for refund of the $42 million of under-recovered pre-2002 reallocated purchased power costs.

Management cannot predict the outcome of the pending fuel and purchased power costs and prudence reviews, or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred.

Oklahoma Rate Filing – Affecting PSO

In November 2006, PSO filed a request to increase base rates by $50 million for Oklahoma jurisdictional customers and set return on equity at 11.75% with a proposed effective date in the second quarter of 2007. PSO also proposed a formula rate plan that, if approved as filed, would permit PSO to defer any unrecovered costs as a result of a revenue deficiency that exceeds 50 basis points of the allowed return on equity for recovery within twelve months beginning six months after the test year. The proposed formula rate plan would enable PSO to recover on a timely basis the cost of its new generation, transmission and distribution construction (including carrying costs during construction), provide the opportunity to achieve the approved return on equity and prevent the capitalization of a significant amount of AFUDC that would have been recorded during the construction period and recovered in the future through depreciation expense.

The ALJ issued a report in May 2007 recommending a 10.5% return on equity but did not compute an overall revenue requirement. The ALJ's report did not recommend adopting a formula rate plan, but did recommend recovery through a rider of certain generation and transmission projects' financing costs during construction. However, the report also contained an alternative recommendation that the OCC could delay a decision on the rider and take up this issue in PSO's application seeking regulatory approval of a new coal-fueled generating unit. PSO implemented interim rates, subject to refund, for residential customers beginning July 2007.

In October 2007, the OCC issued a final order providing for a $10 million annual increase in base rates with a return on equity of 10%. The final order also provides for lower depreciation rates, which PSO estimates will decrease depreciation expense by approximately $10 million on an annual basis. PSO estimates the annual impact of this final order will increase PSO's pretax income by $20 million. The final order also requires PSO to file a plan with the OCC to promote energy efficiency and conservation programs within 60 days. PSO implemented the approved rates in October 2007.

Lawton and Peaking Generation Settlement Agreement – Affecting PSO

In November 2003, pursuant to an application by Lawton Cogeneration, L.L.C. (Lawton) seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court (the Court). In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Court issued a decision in June 2005, affirming portions of the OCC's order and remanding certain provisions. The Court affirmed the OCC's finding that Lawton established a legally-enforceable obligation and ruled that it was within the OCC's discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO's avoided energy cost. Hearings were held on the remanded issues in April and May 2006.

In April 2007, all parties in the case filed a settlement agreement with the OCC resolving all issues. The OCC approved the settlement agreement in April 2007. The OCC staff, the Attorney General, the Oklahoma Industrial Energy Consumers and Lawton Cogeneration, L.L.C. supported this settlement agreement. The settlement agreement provides for a purchase fee of $35 million to be paid by PSO to Lawton and for Lawton to provide, at PSO's direction, all rights to the Lawton Cogeneration Facility including permits, options and engineering studies. PSO paid the $35 million purchase fee in June 2007 and recorded the purchase fee as a regulatory asset and will recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service, currently expected to be 2008. PSO expects these units will have a substantially lower plant-in-service cost than the proposed Lawton Cogeneration Facility. PSO may request approval from the OCC for recovery of costs exceeding the cost cap if special circumstances occur necessitating a higher level of costs. Such costs will continue to be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. Under the settlement, PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units.

Red Rock Generating Facility – Affecting PSO

In July 2006, PSO announced plans to enter into an agreement with Oklahoma Gas and Electric (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit at the site of OG&E's existing Sooner Plant near Red Rock, in north central Oklahoma. PSO would own 50% of the new unit, OG&E would own approximately 42% and the Oklahoma Municipal Power Authority (OMPA) would own approximately 8%. OG&E would manage construction of the plant. OG&E and PSO requested pre-approval to construct the Red Rock Generating Facility and implement a recovery rider. In March 2007, the OCC consolidated PSO's pre-approval application with OG&E's request. The Red Rock Generating Facility was estimated to cost $1.8 billion and was expected to be in service in 2012. The OCC staff and the ALJ recommended the OCC approve PSO's and OG&E's filing. As of September 2007, PSO incurred approximately $20 million of pre-construction costs and contract cancellation fees.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but denied PSO's and OG&E's application for construction pre-approval stating PSO and OG&E failed to fully study other alternatives. Since PSO and OG&E could not obtain pre-approval to build the Red Rock Generating Facility, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. Management believes the pre-construction costs capitalized, including any cancellation fees, were prudently incurred, as evidenced by the OCC staff and the ALJ's recommendations that the OCC approve PSO's filing, and established a regulatory asset for future recovery. Management believes such pre-construction costs are probable of recovery and intends to seek full recovery of such costs in the near future. If recovery is denied, future results of operations and cash flows would be adversely affected. As a result of the OCC's decision, PSO will consider various alternative options to meet its capacity needs in the future.

2007 Oklahoma Ice Storm – Affecting PSO

In October 2007, PSO filed with the OCC requesting recovery of $13 million of operation and maintenance expenses related to service restoration effort after a January 2007 ice storm. PSO proposed to establish a regulatory asset of $13 million and to amortize this asset coincident with the gains from the sale of SO_2 allowances made during 2007 and thereafter until such gains provide for the full recovery of the regulatory asset. If the OCC adopts the PSO proposal, it would have a favorable impact on future results of operations and cash flows.

Louisiana Rate Matters

Louisiana Compliance Filing – Affecting SWEPCo

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

In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdictional customers, based on a proposed 10% return on equity. The recommended reduction range was subject to SWEPCo validating certain ongoing operations and maintenance expense levels. SWEPCo filed rebuttal testimony in October 2006 strongly refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo filed rebuttal testimony in January 2007. Constructive settlement negotiations are making meaningful progress. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely affect future results of operations, cash flows and possibly financial condition.

Stall Unit – Affecting SWEPCo

In May 2006, SWEPCo announced plans to build a new intermediate load 480 MW natural gas-fired combustion turbine combined cycle generating unit at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings with the PUCT and the Arkansas Public Service Commission (APSC) during the third quarter of 2006 and the LPSC during the first quarter of 2007 to seek approvals to construct the unit. The Stall Unit is estimated to cost $375 million, excluding AFUDC, and expected to be in service in mid-2010. As of September 2007, SWEPCo incurred and capitalized approximately $15 million and has contractual commitments of an additional $17 million.

In March 2007, the PUCT approved SWEPCo's request. In Louisiana, this request has been separated from the original request, which included the Turk Plant. Neither the LPSC nor the APSC have set a procedural schedule for the project. The project is contingent upon obtaining pre-approval from the APSC, the LPSC, the PUCT and the Louisiana Department of Environmental Quality. If SWEPCo is not authorized to build the Stall Unit, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred costs, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

Turk Plant – Affecting SWEPCo

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

Arkansas Rate Matters

Turk Plant – Affecting SWEPCo

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named Turk Plant. SWEPCo submitted filings with the APSC in December 2006 and the PUCT and LPSC in February 2007 to seek approvals to proceed with the plant. In September 2007, OMPA signed a joint ownership agreement and agreed to own approximately 7% of the Turk Plant. SWEPCo continues discussions with Arkansas Electric Cooperative Corporation and North Texas Electric Cooperative to become potential partners in the Turk Plant. SWEPCo anticipates owning approximately 73% of the Turk Plant and will operate the facility. The Turk Plant is estimated to cost $1.3 billion in total with SWEPCo's portion estimated to cost $950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in mid-2011. As of September 2007, SWEPCo incurred and capitalized approximately $206 million and has contractual commitments for an additional $875 million. If SWEPCo is not authorized to build the Turk plant, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred cots, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

In August 2007, hearings began before the APSC seeking pre-approval of the plant. The APSC staff recommended the application be approved and intervenors requested the motion be denied. In October 2007, final briefs and closing arguments were completed by all parties during which the APSC staff and Attorney General supported the plant. A decision by the APSC will occur within 60 days from October 22, 2007. In September 2007, the PUCT staff recommended that SWEPCo's application be denied suggesting the construction of the Turk Plant would adversely impact the development of competition in the SPP zone. The PUCT hearings were held in October 2007. The LPSC held hearings in September 2007 and during this proceeding, the LPSC staff expressed support for the project. If SWEPCo is not authorized to build the Turk plant, it could adversely affect future results of operations, cash flows and possibly financial condition if SWEPCo cannot recover incurred costs, including any cancellation fees.

Stall Unit – Affecting SWEPCo

See "Stall Unit" section within Louisiana Rate Matters for disclosure.

FERC Rate Matters

Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP and other transmission owners in the region covered by PJM and MISO eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. APCo's, CSPCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)
APCo	$ 70.2
CSPCo	38.8

I&M	41.3
OPCo	53.3

Approximately $10 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of the AEP East companies' SECA customers. APCo's, CSPCo's, I&M's and OPCo's portions of the reserve are as follows:

Company	**(in millions)**
APCo	$ 12.0
CSPCo	6.7
I&M	7.0
OPCo	9.1

The AEP East companies reached settlements with certain SECA customers related to approximately $69 million of such revenues for a net refund of $3 million. The AEP East companies are in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and will consume about $7 million of the reserves for refunds, leaving approximately $115 million of contested SECA revenues and $30 million of refund reserves. If the ALJ's initial decision were upheld in its entirety, it would disallow approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on recent settlement experience and the expectation that most of the $115 million of unsettled SECA revenues will be settled, management believes that the remaining reserve of $30 million will be adequate to cover all remaining settlements.

In September 2006, AEP, together with Exelon Corporation and The Dayton Power and Light Company, filed an extensive post-hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining $115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations, cash flows and financial condition.

The FERC PJM Regional Transmission Rate Proceeding

In January 2005, certain transmission owners in PJM proposed continuation of the zonal rate design in PJM after the June 2005 FERC deadline. With the elimination of T&O rates and the expiration of SECA rates, zonal rates would provide the AEP System no revenue for use of its transmission facilities by other parties in PJM and the MISO. AEP protested the zonal rate proposal and at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate the AEP East companies 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 proposed and supported a new PJM rate regime generally referred to as a Highway/Byway 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 the Highway/Byway proposed rates to be just and reasonable alternatives. The ALJ also found FERC staff's proposed Postage Stamp rate to be just and reasonable and recommended that 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.

In April 2007, the FERC issued an order reversing the ALJ's decision. The FERC ruled that the current PJM rate design is just and reasonable for existing transmission facilities. However, the FERC ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. As a result of this order, the AEP East companies' retail customers will bear the full cost of the existing AEP east transmission zone facilities. Presently AEP is collecting the full cost of those facilities from its retail customers with the exception of Indiana and Michigan customers. As a result of this order, the AEP East companies' customers will also be charged a share of the cost of future new 500 kV and higher voltage transmission facilities built in PJM, most of which are expected to be upgrades of the facilities in other zones of PJM. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them as a result of this order, if upheld. AEP has requested rehearing of this order. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new east transmission facilities, results of operations, cash flows and financial condition. In May 2007, the AEP East companies filed for rehearing related to this FERC decision.

Since the FERC's decision in 2005 to cease through-and-out rates and replace them temporarily with SECA rates, which ceased on April 1, 2006, the AEP East companies increased their retail rates in all states except Indiana, Michigan and Tennessee to recover lost T&O and SECA revenues. The AEP East companies presently recover from retail customers approximately 85% of the lost T&O/SECA transmission revenues of $128 million a year. Future results of operations, cash flows and financial condition will continue to be adversely affected in Indiana, Michigan and Tennessee until these lost T&O/SECA transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, voted to continue zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore a regional rate design change is required to recognize the provision and use of transmission service in the Super Region since it is not sufficiently uniform between transmission owners and users to justify zonal rates. Management is unable to predict the outcome of this case.

SPP Transmission Formula Rate Filing – Affecting PSO and SWEPCo

In June 2007, AEPSC filed revised tariff sheets on behalf of PSO and SWEPCo for the AEP pricing zone of the SPP OATT. The revised tariff sheets seek to establish an up-to-date revenue requirement for SPP transmission services over the facilities owned by PSO and SWEPCo and implement a transmission cost of service formula rate.

PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. The primary impact of the filed revised tariff will be an increase in network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP pricing zone of SPP. If the proposed formula rate and requested return on equity are approved, the 2008 network transmission service revenues from nonaffiliates will increase by approximately $10 million compared to the revenues that would result from the presently approved network transmission rate. PSO and SWEPCo take service under the same rate, and will also incur the increased OATT charges resulting from the filing, but will receive corresponding revenue to offset the increase. In August 2007, the FERC issued an order conditionally accepting PSO's and SWEPCo's proposed formula rate, subject to a compliance filing, suspended the effective date until February 1, 2008 and established hearing and settlement judge proceedings. In October 2007, AEPSC submitted a compliance filing on behalf of PSO and SWEPCo. Multiple intervenors have protested or requested re-hearing of the order. Discovery and settlement discussions have begun.

PJM Marginal-Loss Pricing – Affecting APCo, CSPCo, I&M and OPCo

On June 1, 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads. Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through September 30, 2007, AEP experienced an increase in the cost of delivering energy from the generating plant locations to customer load zones partially offset by cost recoveries and increased off-system sales resulting in a net loss of approximately $25 million. APCo's, CSPCo's, I&M's and OPCo's portions of the loss are as follows:

Company	(in millions)	
APCo	$	6
CSPCo		5
I&M		5
OPCo		5

AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue through the appropriate stakeholder processes a modification of such methodology. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and is seeking recovery in current and future fuel or base rate filings as appropriate in each of its eastern zone states. In the interim, these costs will have an adverse effect on future results of operations and cash flows. Management is unable to predict whether full recovery will ultimately be approved.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2006 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At September 30, 2007, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, with maturities ranging from December 2007 to March 2008.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of September 30, 2007, SWEPCo collected approximately $33 million through a rider for final mine closure costs, which is recorded in Deferred Credits and Other on SWEPCo's Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs through its fuel clause.

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to September 30, 2007, the Registrant Subsidiaries entered into sale agreements including indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements as of September 30, 2007 was as follows:

Company	Maximum Potential Loss (in millions)	
APCo	$	9
CSPCo		4
I&M		6
OPCo		8
PSO		5
SWEPCo		6

CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA, certain special interest groups and a number of states allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at the AEP System's generating units over a 20-year period. In April 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding.

On October 9, 2007, management announced that the AEP System had entered into a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree the AEP System agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. In addition to completing the installation of previously announced environmental retrofit projects at many of the plants, including the installation of flue gas desulfurization (FGD or scrubbers) equipment at KPCo's Big Sandy Plant and at OPCo's Muskingum River Plant by the end of 2015, AEGCo and I&M agreed to install selective catalytic reduction (SCR) and FGD emissions control equipment on their jointly owned generating units at the Rockport Plant. Unit 1 at the Rockport Plant will be retrofit by the end of 2017, and Unit 2 will be retrofit by the end of 2019. APCo also agreed to install selective non-catalytic reduction, a NO_x-reduction technology, by the end of 2009 at the Clinch River Plant.

Since 2004, the AEP System spent nearly $2.6 billion on installation of emissions control equipment on coal-fueled plants in Kentucky, Ohio, Virginia and West Virginia as part of a larger plan to invest more than $5.1 billion by 2010 to reduce the emissions of the generating fleet. Capital amounts by Registrant Subsidiary are as follows:

	Incurred Capital Amount Through December 31, 2006		Budgeted Capital 2007 - 2010	
	(in millions)			
APCo	$	923	$	944
CSPCo		194		374

I&M	98	77
OPCo	1,253	891

Management agreed to operate SCRs year round during 2008 at APCo's Mountaineer Plant, OPCo's Muskingum River Plant and APCo's and OPCo's jointly owned Amos Plant, and agreed to plant-specific SO_2 emission limits for Clinch River Plant and OPCo's Kammer Plant.

Under the consent decree, the AEP System will pay a $15 million civil penalty and provide $36 million for environmental projects coordinated with the federal government and $24 million to the states for environmental mitigation. The Registrant Subsidiaries expensed their share of these amounts in third quarter of 2007 as follows:

	Penalty	Environmental Mitigation Costs	Total Expensed in September 2007
		(in thousands)	
APCo	$ 4,974	$ 20,659	$ 25,633
CSPCo	2,883	11,973	14,856
I&M	2,770	11,503	14,273
OPCo	3,355	13,935	17,290

The consent decree will resolve all issues related to various parties' claims against the Registrant Subsidiaries in the two pending NSR cases. The consent decree has been filed with the U.S. District Court. The consent decree is subject to a 30-day public comment period and final approval by the Court. A hearing on the motion to approve the consent decree is scheduled for December 10, 2007.

Management believes that APCo, CSPCo, I&M and OPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If they are unable to recover such costs, it would adversely affect their future results of operations, cash flows and possibly financial condition.

Cases are pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned), and Stuart (26% owned) stations. No trial date has yet been established in the Stuart case, but the units, operated by Dayton Power and Light Company, are equipped with SCR controls and the installation of FGD controls will be completed in 2007. The Beckjord and Zimmer case is scheduled for a liability trial in May 2008. Zimmer is equipped with both FGD and SCR controls. Beckjord and Zimmer are operated by Duke Energy Ohio, Inc. 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.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, CSPCo might have for civil penalties under the pending CAA proceedings for the jointly-owned plants. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If CSPCo does not prevail, management believes CSPCo can recover any capital and operating costs of additional pollution control equipment that may be required through market prices for electricity. If any of the AEP subsidiaries are unable to recover their capital and operating costs or if material penalties are imposed for CSPCo's jointly-owned plants, it would adversely affect future results of operations, cash flows and possibly financial condition.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled to commence during the first quarter of 2008.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007 removing the heat input references from the Welsh permit and clarifying the sulfur content of fuels burned at the plant is limited to 0.5% on an as-received basis. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion.

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

Carbon Dioxide (CO_2) Public Nuisance Claims – Affecting AEP East Companies and AEP West Companies

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

TEM Litigation – Affecting OPCo

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

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

In 2005, a federal judge ruled that TEM had breached the contract and awarded damages to OPCo of $123 million plus prejudgment interest. Any eventual proceeds will not impact OPCo's income statement due to the indemnification agreement with AEP Resources (AEPR), a nonutility subsidiary of AEP, whereby AEPR held OPCo harmless from market exposure related to the PPA.

In May 2007, the United States Court of Appeals for the Second Circuit ruled that the lower court was correct in finding that TEM breached the PPA and OPCo did not breach the PPA. It also ruled that the lower court applied an incorrect standard in denying OPCo any damages for TEM's breach of the 20-year term of the PPA holding that OPCo is entitled to the benefit of its bargain and that the trial court must determine damages. The Court of Appeals vacated approximately $117 million of the $123 million judgment for damages against TEM related to replacement products and remanded the issue for further proceedings to determine the correct amount of those damages. One part of the judgment is final, that involves TEM's liability for damages applicable to gas peaking and post-actual commercial operation date products. OPCo expects TEM to pay the amount of those damages, approximately $8 million, including interest, in the fourth quarter of 2007.

Coal Transportation Dispute – Affecting PSO

PSO, TCC, TNC, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed. In September 2007, the Surface Transportation Board ruled that the disputed rates were not unreasonable under the standalone cost rate test. The joint owners filed a Petition for Reconsideration. Based upon this ruling, PSO, as operator of the plant, adjusted the provision recorded in prior periods. PSO deferred its immaterial share of the provision under its fuel mechanism after mitigation by certain contractual rights.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In February 2007, the U.S. District Court granted BNSF's Motion to Reconsider. PSO filed a substantive response to BNSF's motion and BNSF filed a reply. Management continues to work toward mitigating the disputed amounts to the extent possible.

FERC Long-term Contracts – Affecting AEP East Companies and AEP West Companies

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. An ALJ recommended rejection of the complaint, holding that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. On September 25, 2007, the U.S. Supreme Court decided to review the Ninth Circuit's decision. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. The Registrant Subsidiaries asserted claims against certain companies that sold power to them, which was resold to the Nevada utilities, seeking to recover a portion of any amounts the Registrant Subsidiaries may owe to the Nevada utilities.

5. ACQUISITION

Darby Electric Generating Station – Affecting CSPCo

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

6. BENEFIT PLANS

The Registrant Subsidiaries participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, the Registrant Subsidiaries participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

The Registrant Subsidiaries adopted SFAS 158 as of December 31, 2006. The Registrant Subsidiaries recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes are deferred for future recovery.

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the three and nine months ended September 30, 2007 and 2006:

	Pension Plans		Other Postretirement Benefit Plans	
	2007	**2006**	**2007**	**2006**
Three Months Ended September 30, 2007 and 2006		**(in millions)**		
Service Cost	$ 24	$ 23	$ 11	$ 10
Interest Cost	59	57	26	26
Expected Return on Plan Assets	(85)	(82)	(26)	(24)
Amortization of Transition Obligation	-	-	6	7
Amortization of Net Actuarial Loss	15	20	3	5
Net Periodic Benefit Cost	$ 13	$ 18	$ 20	$ 24

Other Postretirement

	Pension Plans		Benefit Plans	
	2007	2006	2007	2006
Nine Months Ended September 30, 2007 and 2006		(in millions)		
Service Cost	$ 72	$ 71	$ 32	$ 30
Interest Cost	176	171	78	76
Expected Return on Plan Assets	(254)	(248)	(78)	(70)
Amortization of Transition Obligation	-	-	20	21
Amortization of Net Actuarial Loss	44	59	9	15
Net Periodic Benefit Cost	$ 38	$ 53	$ 61	$ 72

The following table provides the net periodic benefit cost (credit) for the plans by Registrant Subsidiary for the three and nine months ended September 30, 2007 and 2006:

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Three Months Ended September 30, 2007 and 2006		(in thousands)		
APCo	$ 841	$ 1,469	$ 3,560	$ 4,487
CSPCo	(258)	205	1,491	1,807
I&M	1,900	2,331	2,530	2,949
OPCo	362	823	2,802	3,395
PSO	425	979	1,431	1,588
SWEPCo	747	1,222	1,420	1,578

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Nine Months Ended September 30, 2007 and 2006		(in thousands)		
APCo	$ 2,525	$ 4,406	$ 10,680	$ 13,465
CSPCo	(773)	615	4,473	5,417
I&M	5,700	6,992	7,591	8,855
OPCo	1,088	2,478	8,405	10,187
PSO	1,273	2,935	4,292	4,764
SWEPCo	2,240	3,672	4,258	4,734

7. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. INCOME TAXES

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

Audit Status

The Registrant Subsidiaries also file income tax returns in various state and local jurisdictions. With few exceptions, the Registrant Subsidiaries are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2000. The IRS and other taxing authorities routinely examine the tax returns. Management believes that the Registrant Subsidiaries have filed tax returns with positions that may be challenged by the tax authorities. The Registrant Subsidiaries are currently under examination in several state and local jurisdictions. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations.

The AEP System settled with the IRS on all issues from the audits of consolidated federal income tax returns for years prior to 1997. The AEP System effectively settled all outstanding proposed IRS adjustments for years 1997 through 1999 and through June 2000 for the CSW pre-merger tax period and anticipates payment for the agreed adjustments to occur during 2007. Returns for the years 2000 through 2005 are presently being audited by the IRS and management anticipates that the audit of the 2000 through 2003 years will be completed by the end of 2007.

FIN 48 Adoption

The Registrant Subsidiaries adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the approximate increase (decrease) in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings was recognized by each Registrant Subsidiary as follows:

Company	**(in thousands)**
APCo	$ 2,685
CSPCo	3,022
I&M	(327)
OPCo	5,380
PSO	386
SWEPCo	1,642

At January 1, 2007, the total amount of unrecognized tax benefits under FIN 48 for each Registrant Subsidiary was as follows:

Company	**(in millions)**
APCo	$ 21.7
CSPCo	25.0
I&M	18.2
OPCo	49.8
PSO	8.9
SWEPCo	7.1

Management believes it is reasonably possible that there will be a net decrease in unrecognized tax benefits due to the settlement of audits and the expiration of statute of limitations within 12 months of the reporting date for each

Registrant Subsidiary as follows:

Company	(in millions)
APCo	$ 5.5
CSPCo	9.3
I&M	6.0
OPCo	9.0
PSO	4.4
SWEPCo	2.8

At January 1, 2007, the total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant Subsidiary was as follows:

Company	(in millions)
APCo	$ 5.4
CSPCo	13.8
I&M	5.4
OPCo	23.4
PSO	1.2
SWEPCo	1.2

At January 1, 2007, tax positions for each Registrant Subsidiary, for which the ultimate deductibility is highly certain but the timing of such deductibility is uncertain, was as follows:

Company	(in millions)
APCo	$ 13.7
CSPCo	3.9
I&M	10.3
OPCo	14.2
PSO	7.1
SWEPCo	5.1

Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

Prior to the adoption of FIN 48, the Registrant Subsidiaries recorded interest and penalty accruals related to income tax positions in tax accrual accounts. With the adoption of FIN 48, the Registrant Subsidiaries began recognizing interest accruals related to income tax positions in interest expense and penalties in Other Operations. As of January 1, 2007, each Registrant Subsidiary accrued for the payment of uncertain interest and penalties as follows:

Company	(in millions)
APCo	$ 4.6
CSPCo	1.7
I&M	2.8
OPCo	4.3
PSO	2.7

SWEPCo	2.0

Michigan Tax Restructuring (Affecting I&M)

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law is effective January 1, 2008 and replaces the Michigan Single Business Tax that is scheduled to expire at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198 which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15 year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. The registrant subsidiaries have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect their results of operations, cash flows or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2007 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$ 75,000	Variable	2037
APCo	Senior Unsecured Notes	250,000	5.65	2012
APCo	Senior Unsecured Notes	250,000	6.70	2037
CSPCo	Pollution Control Bonds	44,500	Variable	2040
OPCo	Pollution Control Bonds	65,000	4.90	2037
OPCo	Senior Unsecured Notes	400,000	Variable	2010
PSO	Pollution Control Bonds	12,660	4.45	2020
SWEPCo	Senior Unsecured	250,000	5.55	2017

Notes

In May 2007, I&M remarketed its outstanding $50 million Pollution Control Bonds, resulting in a new interest rate of 4.625%. No proceeds were received related to this remarketing. The principal amount of the Pollution Control Bonds is reflected in Long-term Debt on I&M's Condensed Consolidated Balance Sheet as of September 30, 2007.

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Senior Unsecured Notes	$ 125,000	Variable	2007
APCo	Other	9	13.718	2026
OPCo	Notes Payable – Nonaffiliated	2,927	6.81	2008
OPCo	Notes Payable – Nonaffiliated	6,000	6.27	2009
PSO	Pollution Control Bonds	12,660	6.00	2020
SWEPCo	First Mortgage Bonds	90,000	7.00	2007
SWEPCo	Notes Payable – Nonaffiliated	4,210	4.47	2011
SWEPCo	Notes Payable – Nonaffiliated	4,000	6.36	2007
SWEPCo	Notes Payable – Nonaffiliated	2,250	Variable	2008

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of September 30, 2007 and December 31, 2006 are included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the nine months ended September 30, 2007 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans/ (Borrowings) to/from Utility Money Pool as of September 30, 2007	Authorized Short-Term Borrowing Limit
			(in thousands)			
APCo	$ 406,262	$ 96,543	$ 147,582	$ 48,303	$ 38,573	$ 600,000
CSPCo	137,696	35,270	51,927	13,551	(123,043)	350,000
I&M	100,374	52,748	50,998	34,749	(24,234)	500,000
OPCo	447,335	1,564	161,746	1,564	(85,341)	600,000

PSO	242,097	-	133,404	-	(187,492)	300,000
SWEPCo	240,786	48,979	79,890	29,653	(155,869)	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Maximum Interest Rate	5.94%	5.41%
Minimum Interest Rate	5.30%	3.63%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 30, 2007 and 2006 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30,	
	2007	2006	2007	2006
Company		(in percentage)		
APCo	5.41	4.62	5.84	4.98
CSPCo	5.48	4.73	5.39	4.63
I&M	5.38	4.81	5.84	-
OPCo	5.39	4.83	5.43	5.12
PSO	5.47	5.02	-	4.36
SWEPCo	5.54	5.01	5.34	4.36

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		September 30, 2007		December 31, 2006	
Company	Type of Debt	Outstanding Amount (in millions)	Interest Rate	Outstanding Amount (in millions)	Interest Rate
OPCo	Commercial Paper – JMG	$ 2	5.3588%	$ 1	5.56%
SWEPCo	Line of Credit – Sabine	26	6.07%	17	6.38%

Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.

Sale of Receivables – AEP Credit

In October 2007, AEP renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $650 million from a bank conduit to purchase receivables from AEP Credit. Under the agreement, the commitment will increase to $700 million in August and September to accommodate seasonal demand. This agreement will expire in October 2008. AEP Credit purchases accounts receivable through purchase agreements with CSPCo, I&M, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements and (iii) footnotes of each individual registrant. The combined Management's Discussion and Analysis of Registrant Subsidiaries section of the 2006 Annual Report should also be read in conjunction with this report.

Significant Factors

Ohio Restructuring

As permitted by the current Ohio restructuring legislation, CSPCo and OPCo can implement market-based rates effective January 2009, following the expiration of its RSPs on December 31, 2008. In August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. In place of market-based rates, it is more likely that some form of cost-based rates or hybrid-based rates would be required. The legislation passed through the Ohio Senate and still must be considered by the Ohio House of Representatives. Management continues to analyze the proposed legislation and is working with various stakeholders to achieve a principled, fair and well-considered approach to electric supply pricing. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009.

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP and other transmission owners in the region covered by PJM and MISO eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. APCo's, CSPCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)
APCo	$ 70.2
CSPCo	38.8
I&M	41.3
OPCo	53.3

Approximately $10 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of the AEP East companies' SECA customers. APCo's, CSPCo's, I&M's and OPCo's portions of the reserve are as follows:

Company		(in millions)
APCo	$	12.0
CSPCo		6.7
I&M		7.0
OPCo		9.1

The AEP East companies reached settlements with certain SECA customers related to approximately $69 million of such revenues for a net refund of $3 million. The AEP East companies are in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and will consume about $7 million of the reserves for refunds, leaving approximately $115 million of contested SECA revenues and $30 million of refund reserves. If the ALJ's initial decision were upheld in its entirety, it would disallow approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on recent settlement experience and the expectation that most of the $115 million of unsettled SECA revenues will be settled, management believes that the remaining reserve of $30 million will be adequate to cover all remaining settlements.

In September 2006, AEP, together with Exelon Corporation and The Dayton Power and Light Company, filed an extensive post-hearing brief and reply brief noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining $115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations, cash flows and financial condition.

PJM Marginal-Loss Pricing

On June 1, 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads. Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through September 30, 2007, AEP experienced an increase in the cost of delivering energy from the generating plant locations to customer load zones partially offset by cost recoveries and increased off-system sales resulting in a net loss of approximately $25 million. APCo's, CSPCo's, I&M's and OPCo's portions of the loss are as follows:

Company		(in millions)
APCo	$	6
CSPCo		5
I&M		5
OPCo		5

AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue through the appropriate stakeholder processes a modification of such methodology. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and is seeking recovery in current and future fuel or base rate filings as appropriate in each of its eastern zone states. In the interim, these costs will have an adverse effect on future results of operations and cash flows. Management is unable to predict whether full recovery will ultimately be approved.

New Generation

AEP is in various stages of construction of the following generation facilities. Certain plants are pending regulatory approval:

Operating Company	Project Name		Location	Total Projected Cost (a) (in millions)	CWIP (in millions)	Fuel Type	Plant Type	MW Capacity		Commercial Operation Date (Projected)
SWEPCo	Mattison		Arkansas	$ 122(b)	$ 52	Gas	Simple-cycle	340	(b)	2007
PSO	Southwestern		Oklahoma	59(c)	45	Gas	Simple-cycle	170		2008
PSO	Riverside		Oklahoma	58(c)	45	Gas	Simple-cycle	170		2008
AEGCo	Dresden	(d)	Ohio	265(d)	88	Gas	Combined-cycle	580		2009
SWEPCo	Stall		Louisiana	375	15	Gas	Combined-cycle	480		2010
SWEPCo	Turk	(e)	Arkansas	1,300(e)	206	Coal	Ultra-supercritical	600	(e)	2011
APCo	Mountaineer		West Virginia	2,230	-	Coal	IGCC	629		2012
CSPCo/OPCo	Great Bend		Ohio	2,230(f)	-	Coal	IGCC	629		2017

(a) Amount excludes AFUDC.
(b) Includes Unites 3 and 4, 150 MW, declared in commercial operation on July 12, 2007 with construction costs totaling $55 million.
(c) In April 2007, the OCC approved that PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service at the time these units are placed in service.
(d) In September 2007, AEGCo purchased the under-construction Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(e) SWEPCo plans to own approximately 73%, or 438 MW, totaling about $950 million in capital investment. See "Turk Plant" section below.
(f) Front-end engineering and design study is complete. Cost estimates are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 2006 opinion and order. See "Ohio IGCC Plant" section below.

AEP acquired the following generation facilities:

Operating Company	Plant Name	Location	Cost	Fuel Type	Plant Type	MW Capacity	Purchase Date

				(in millions)				
CSPCo	Darby	(a)	Ohio	$ 102	Gas	Simple-cycle	480	April 2007
AEGCo	Lawrenceburg	(b)	Indiana	325	Gas	Combined-cycle	1,096	May 2007

(a) CSPCo purchased Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company.
(b) AEGCo purchased Lawrenceburg Generating Station (Lawrenceburg), adjacent to I&M's Tanners Creek Plant, from an affiliate of Public Service Enterprise Group (PSEG). AEGCo sells the power to CSPCo under a FERC-approved unit power agreement.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of $24 million in pre-construction costs during 2006; Phase 2, concurrent recovery of construction-financing costs; and Phase 3, recovery or refund in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the ultimate cost to construct the plant, originally projected to be $1.2 billion, along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the average 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo 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 a period of no more than twelve months effective July 1, 2006. Through September 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. As of September 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered.

The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs collected for pre-construction costs, associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

In August 2006, the Ohio Industrial Energy Users, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio Supreme Court heard oral arguments for these appeals in October 2007. Management believes that the PUCO's authorization to begin collection of Phase 1 pre-construction costs is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund Phase 1 cost-related recoveries.

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant have escalated to $2.2 billion. CSPCo and OPCo may need to request an extension to the 5-year start of construction requirement if the commencement of construction is delayed beyond 2011.

Red Rock Generating Facility

In July 2006, PSO announced plans to enter into an agreement with Oklahoma Gas and Electric (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit at the site of OG&E's existing Sooner Plant near Red Rock, in north central Oklahoma. PSO would own 50% of the new unit, OG&E would own approximately 42% and the Oklahoma Municipal Power Authority (OMPA) would own approximately 8%. OG&E would manage construction of the plant. OG&E and PSO requested pre-approval to construct the Red Rock Generating Facility and implement a recovery rider. In March 2007, the OCC consolidated PSO's pre-approval application with OG&E's request. The Red Rock Generating Facility was estimated to cost $1.8 billion and was expected to be in service in 2012. The OCC staff and the ALJ recommended the OCC approve PSO's and OG&E's filing. As of September 2007, PSO incurred approximately $20 million of pre-construction costs and contract cancellation fees.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but denied PSO's and OG&E's application for construction pre-approval stating PSO and OG&E failed to fully study other alternatives. Since PSO and OG&E could not obtain pre-approval to build the Red Rock Generating Facility, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. Management believes the pre-construction costs capitalized, including any cancellation fees, were prudently incurred, as evidenced by the OCC staff and the ALJ's recommendations that the OCC approve PSO's filing, and established a regulatory asset for future recovery. Management believes such pre-construction costs are probable of recovery and intends to seek full recovery of such costs in the near future. If recovery is denied, future results of operations and cash flows would be adversely affected. As a result of the OCC's decision, PSO will be re-considering various alternative options to meet its capacity needs in the future.

Turk Plant

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named Turk Plant. SWEPCo submitted filings with the Arkansas Public Service Commission (APSC) in December 2006 and the PUCT and LPSC in February 2007 to seek approvals to proceed with the plant. In September 2007, OMPA signed a joint ownership agreement and agreed to own approximately 7% of the Turk Plant. SWEPCo continues discussions with Arkansas Electric Cooperative Corporation and North Texas Electric Cooperative to become potential partners in the Turk Plant. SWEPCo anticipates owning approximately 73% of the Turk Plant and will operate the facility. The Turk Plant is estimated to cost $1.3 billion in total with SWEPCo's portion estimated to cost $950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in mid-2011. As of September 2007, SWEPCo incurred and capitalized approximately $206 million and has contractual commitments for an additional $875 million. If the Turk Plant is not approved, cancellation fees may be required to terminate SWEPCo's commitment.

In August 2007, hearings began before the APSC seeking pre-approval of the plant. The APSC staff recommended the application be approved and intervenors requested the motion be denied. In October 2007, final briefs and closing arguments were completed by all parties during which the APSC staff and Attorney General supported the plant. A decision by the APSC will occur within 60 days from October 22, 2007. In September 2007, the PUCT staff recommended that SWEPCo's application be denied suggesting the construction of the Turk Plant would adversely impact the development of competition in the SPP zone. The PUCT hearings were held in October 2007. The LPSC held hearings in September 2007 and during this proceeding, the LPSC staff expressed support for the project. If SWEPCo is not authorized to build the Turk plant, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred costs, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

Environmental Matters

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the Clean Air Act (CAA) to reduce emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM) and mercury from fossil fuel-fired power plants; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain power plants.

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units. Management also monitors possible future requirements to reduce carbon dioxide (CO_2) emissions to address concerns about global climate change. All of these matters are discussed in the "Environmental Matters" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 Annual Report.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging 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. In April 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding.

In October 2007, management announced that the AEP System had entered into a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, the AEP System agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. In addition to completing the installation of previously announced environmental retrofit projects at many of the plants, I&M agreed to install selective catalytic reduction (SCR) and flue gas desulfurization (FGD or scrubbers) emissions control equipment on the Rockport Plant units.

Since 2004, the AEP System spent nearly \$2.6 billion on installation of emissions control equipment on its coal-fueled plants in Kentucky, Ohio, Virginia and West Virginia as part of a larger plan to invest more than \$5.1 billion by 2010 to reduce the emissions of the generating fleet. Capital amounts by Registrant Subsidiary are as follows:

	Incurred Capital Amount Through December 31, 2006	Budgeted Capital 2007 - 2010
	(in millions)	
APCo	$ 923	$ 944
CSPCo	194	374
I&M	98	77
OPCo	1,253	891

Under the consent decree, the AEP System will pay a \$15 million civil penalty and provide \$36 million for environmental projects coordinated with the federal government and \$24 million to the states for environmental mitigation. The Registrant Subsidiaries expensed their share of these amounts in September 2007 as follows:

	Environmental	Total Expensed in

	Penalty		Mitigation Costs (in thousands)		September 2007	
APCo	$	4,974	$	20,659	$	25,633
CSPCo		2,883		11,973		14,856
I&M		2,770		11,503		14,273
OPCo		3,355		13,935		17,290

See "Federal EPA Complaint and Notice of Violation" section of Note 4.

Litigation against CSPCo's three jointly-owned plants, operated by Duke Energy Ohio, Inc. and Dayton Power and Light Company, continues. Management is unable to predict the outcome of these cases. Management believes the Registrant Subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates or market prices for electricity. If the Registrant Subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations and cash flows.

Clean Water Act Regulations

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. Management expected additional capital and operating expenses, which the Federal EPA estimated could be $193 million for AEP System plants. The Registrant Subsidiaries undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates. The following table shows the investment amount per Registrant Subsidiary.

Company	Estimated Compliance Investments (in millions)	
APCo	$	21
CSPCo		19
I&M		118
OPCo		31

The rule was challenged in the courts by states, advocacy organizations and industry. In January 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. Management cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. Management may seek further review or relief from the schedules included in the permits.

<u>Adoption of New Accounting Pronouncements</u>

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. The Registrant Subsidiaries adopted FIN 48 effective January 1, 2007. See "FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48"" section of Note 2 and see Note 8 – Income Taxes. The impact of this interpretation was an unfavorable (favorable) adjustment to retained earnings as follows:

Company	**(in thousands)**
APCo	$ 2,685
CSPCo	3,022
I&M	(327)
OPCo	5,380
PSO	386
SWEPCo	1,642

CONTROLS AND PROCEDURES

During the third quarter of 2007, management, including the principal executive officer and principal financial officer of each of AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of September 30, 2007 these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2007 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 4, *Commitments, Guarantees and Contingencies,* incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2006 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2006 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Our request for rate recovery of plant construction costs may not be approved for SWEPCo. *(Applies to AEP and SWEPCo.)*

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named Turk Plant. SWEPCo submitted filings with the APSC in December 2006 and the PUCT and LPSC in February 2007 to seek approvals to proceed with the plant. In September 2007, OMPA signed a joint ownership agreement and agreed to own approximately 7% of the Turk Plant. SWEPCo continues discussions with Arkansas Electric Cooperative Corporation and North Texas Electric Cooperative to become potential partners in the Turk Plant. SWEPCo anticipates owning approximately 73% of the Turk Plant and will operate the facility. The Turk Plant is estimated to cost $1.3 billion in total with SWEPCo's portion estimated to cost $950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in mid-2011. As of September 2007, SWEPCo incurred and capitalized approximately $206 million and has contractual commitments for an additional $875 million. If the Turk Plant is not approved, cancellation fees may be required to terminate SWEPCo's commitment.

In August 2007, hearings began before the APSC seeking pre-approval of the plant. The APSC staff recommended the application be approved and intervenors requested the motion be denied. In October 2007, final briefs and closing arguments were completed by all parties during which the APSC staff and Attorney General supported the plant. A decision by the APSC will occur within 60 days from October 22, 2007. In September 2007, the PUCT staff recommended that SWEPCo's application be denied suggesting the construction of the Turk Plant would adversely impact the development of competition in the SPP zone. The PUCT hearings were held in October 2007. The LPSC held hearings in September 2007 and during this proceeding, the LPSC staff expressed support for the project. If SWEPCo is not authorized to build the Turk plant, SWEPCo would seek recovery of incurred costs including any cancellation fees. If SWEPCo cannot recover incurred costs, including any cancellation fees, it could adversely affect future results of operations, cash flows and possibly financial condition.

Plant pre-construction costs may not be recovered for PSO. *(Applies to AEP and PSO.)*

In July 2006, PSO announced plans to enter into an agreement with Oklahoma Gas and Electric (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit at the site of OG&E's existing Sooner Plant near Red Rock, in north central Oklahoma. In October 2007, the OCC issued a final order denying PSO's application for construction pre-approval stating PSO failed to fully study other alternatives. As of September 2007, PSO deferred approximately $20 million of pre-construction costs. If recovery of pre-construction costs is denied, future results of operations and cash flows would be adversely affected.

The amount we charged third parties for using our transmission facilities has been reduced, is subject to refund and may not be completely restored in the future. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Intervenors objected to this decision; therefore the SECA fees we collected ($220 million) are subject to refund. Approximately $10 million of the SECA revenues that we billed were never collected. AEP filed a motion with the FERC to force payment of these SECA billings.

A hearing 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 was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory, and that new compliance filings and refunds should be made. The ALJ also found that unpaid SECA rates must be paid in the recommended reduced amount. The FERC has not ruled on the matter. If the FERC upholds the decision of the ALJ, it would disallow $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. We have recorded provisions in the aggregate amount of $37 million related to the potential refund of SECA rates. After completed and in-process settlements of SECA revenues that will consume about $7 million of the reserves for refunds, the AEP East companies will have a remaining reserve balance of $30 million to settle the remaining unsettled gross SECA revenues.

SECA transition rates expired on March 31, 2006 and did not fully compensate AEP East companies for ongoing lost T&O revenues. As a result of rate relief in certain jurisdictions, however, approximately 85% of the ongoing lost T&O revenues are now being recovered from native load customers of AEP East companies in those jurisdictions. The portion attributable to Virginia is being collected subject to refund.

In addition to seeking retail rate recovery from native load customers in the applicable states, AEP and another member of PJM have filed an application with the FERC seeking compensation from other unaffiliated members of PJM for the costs associated with those members' use of the filers' the AEP East companies respective transmission assets. A majority of PJM members have filed in opposition to the proposal. Hearings were held in April 2006. An ALJ recommended a rate design that would result in greater recovery for AEP than the proposal AEP had submitted. The ALJ also recommended, however, that the design be phased-in, which could limit the amount of recovery for AEP. In April 2007, the FERC issued an order reversing the ALJ decision. The FERC ruled that the current PJM rate design is just and reasonable. The FERC further ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. Management cannot estimate at this time what affect, if any, this order will have on our future construction of new east transmission facilities, results of operations, cash flows and financial condition.

The increase in amount PJM charges for transmission line loss may not be recoverable. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

On June 1, 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads. Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through September 30, 2007, AEP experienced an increase in the cost of delivering energy from the generating plant locations to customer load zones partially offset by cost recoveries and increased off-system sales resulting in a net loss of approximately $25 million. AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue through the appropriate stakeholder processes a modification of such methodology. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and is seeking recovery in current and future fuel or base rate filings as appropriate in each of its eastern zone states. In the interim, these costs will have an adverse effect on future results of operations and cash flows. Management is unable to predict whether full recovery will ultimately be approved.

Our nonstatutory surcharges in Kentucky may be invalidated. *(Applies to AEP.)*

In August 2007, the Franklin Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The ruling results from the AG's appeal of the KPSC's approval of a natural gas distribution surcharge for replacement of gas mains. The AG notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could appeal an existing surcharge KPCo is collecting to the Franklin County Circuit Court. KPCo's fuel clause, annual Rockport Plant capacity surcharge, merger surcredit and credit system sales rider are not specifically authorized by statute. These surcharges are currently producing net annual revenues of approximately $10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG's filed brief took the position that the KPCo fuel clause should be invalidated because the KPSC lacked the authority by statute to implement a fuel clause for KPCo without a full rate case review. In August 2007, the KPSC issued an order stating despite the Franklin County Circuit Court decision, the KPSC has the authority to provide for surcharges and surcredits at least until a Court of Appeals ruling. In August 2007, the AG agreed to stipulate to a stay order over the Franklin County Circuit Court's decision pending the appeal decision. KPCo's exposure is indeterminable at this time. If the appeal is unfavorable, future results of operations and cash flows could be adversely affected.

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP.)*

On June 1, 2001, we purchased HPL from Enron Corp. (Enron). Later that year, Enron and its subsidiaries filed bankruptcy proceedings in the U.S. Bankruptcy Court for the Southern District of New York. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 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 (together with BOA, BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Additionally, 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, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. We purchased 10 BCF of gas from Enron and are currently litigating the rights to the remaining 55 BCF of cushion gas. In August 2007, the judge issued a decision granting BOA summary judgment without awarding any damages and dismissing our claims. The judge in the case held another hearing in September 2007 and said that he plans a further hearing on the damages issue. We asked the judge to certify an appeal of the legal issues decided by his summary judgment rulings prior to any ruling on damages. At this time we are unable to predict how the Judge will rule on the pending request. If the judge issues a judgment directing us to pay an amount in excess of the gain on the sale of HPL and if we are unsuccessful in having the judgment reversed or modified, the judgment could have a material adverse effect on results of operations, cash flows, and possibly financial condition.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. In 2005, we sold HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Risks Relating To State Restructuring

In Ohio, our costs may not be recovered and rates may be reduced. *(Applies to AEP, OPCo and CSPCo.)*

In October 2007, CSPCo and OPCo made a filing with the PUCO under the average 4% generation rate provision of their RSPs for an additional increase in their annual generation rates effective January 2008 of $35 million and $12 million, respectively, to recover governmentally-mandated costs and increased costs related to marginal-loss pricing. CSPCo and OPCo will implement these proposed increases in January 2008 and are subject to refund until the PUCO issues a final order in the matter. Management is unable to predict the outcome of this filing and its impact on future results of operations and cash flows.

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. In August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. In place of market-based rates, it is more likely that some form of cost-based rates or hybrid-based rates would be required. The legislation passed through the Ohio Senate and still must be considered by the Ohio House of Representatives. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. In a preliminary ruling filed in February 2007, the Texas state district court (District Court) adjudicating the appeal of the final order in the true-up proceeding found that the PUCT erred in several respects, including the method used to determine stranded costs and the awarding of certain carrying costs. Following the preliminary ruling, the court granted a rehearing of the issue regarding the method to determine stranded costs.

In March 2007, the District Court judge reversed the earlier preliminary decision concluding the sale of assets method to value TCC's nuclear plant was appropriate. It is expected that the parties and intervenors will appeal various portions of the District Court ruling along with other items to the Texas Court of Appeals. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with environmental laws are significant and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to AEP and each Registrant Subsidiary.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from our estimates. All of the costs are incremental to our current investment base and operating cost structure.

If Federal and/or State requirements are imposed on electric utility companies mandating further emission reductions, including limitations on CO_2 emissions, such requirements could make some of our electric generating units uneconomical to maintain or operate. *(Applies to AEP and each Registrant Subsidiary.)*

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA. Future changes in environmental regulations governing these pollutants could make some of our electric generating units uneconomical to maintain or operate. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While mandatory requirements for further emission reductions from our fossil fleet do not appear to be imminent, we continue to monitor regulatory and legislative developments in this area.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations. *(Applies to AEP and each Registrant Subsidiary.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the Federal EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the CAA. The Federal EPA and a number of states alleged that we and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the CAA. The Federal EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period. In October 2007, we announced that we had entered into a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. The consent decree has been filed with the U.S. District Court. The consent decree is subject to a 30-day public comment period and final approval by the Court. A hearing on the motion to approve the consent decree is scheduled for December 10, 2007. Cases are still pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer, and Stuart stations. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal common law. The trial court dismissed the suits and plaintiffs have appealed the dismissal. While we believe the claims are without merit, the costs associated with reducing CO_2 emissions could harm our business and our results of operations and financial position.

If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended September 30, 2007 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
07/01/07 – 07/31/07	93(a)	$ 81.25	-	$ -
08/01/07 – 08/31/07	20(b)	75	-	-
09/01/07 – 09/30/07	1(c)	78	-	-

(a) APCo repurchased 93 shares of its 4.5% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.
(b) APCo repurchased 20 shares of its 4.5% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.
(c) APCo repurchased 1 share of its 4.5% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.

Item 4. Submission of Matters to a Vote of Security Holders

NONE

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP

31(a) – Certification of AEP Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(c) – Certification of AEP Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(b) – Certification of Registrant Subsidiaries' Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(d) – Certification of Registrant Subsidiaries' Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: November 2, 2007