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

Energy/Delivery Summary	**Three Months Ended September 30, 2007**	**2006**	**Nine Months Ended September 30, 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, 2007	**2006**	**Nine Months Ended September 30, 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:

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- 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.

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

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our 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) (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 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 (in millions)**	**2006**	**Nine Months Ended September 30, 2007 (in millions)**	**2006**
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