PUBLIC UTILITY COMMISSION OF TEXAS

Control No. 18661 2005 NOV -8 PM 3:44

Substantive Rule 25.73(c)

SEC FORM -10-Q
For The Quarter Ending September 30, 2005

For

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

NOVEMBER 8, 2005

TABLE OF CONTENTS

226

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, 2005**
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No ___

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes X No ___

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are accelerated filers (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No X

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act.)

Yes ___ No X

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

	Number of Shares of Common Stock Outstanding at October 31, 2005
American Electric Power Company, Inc.	393,684,291
AEP Generating Company	1,000
AEP Texas Central Company	2,211,678
AEP Texas North Company	5,488,560
Appalachian Power Company	13,499,500
Columbus Southern Power Company	16,410,426
Indiana Michigan Power Company	1,400,000
Kentucky Power Company	1,009,000
Ohio Power Company	27,952,473
Public Service Company of Oklahoma	9,013,000
Southwestern Electric Power Company	7,536,640

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORT ON FORM 10-Q
September 30, 2005

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power

Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	M eaning
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
COLI	Corporate owned, life insurance program.
Cook Plant	The 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.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.

DOE	United States Department of Energy.
ECAR	East Central Area Reliability Council.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
GAAP	Generally Accepted Accounting Principles.
HPL	Houston Pipeline Company.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPP	Independent Power Producers.
IURC	Indiana Utility Regulatory Commission.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
ME SWEPCo	Mutual Energy SWEPCo L.P., a Texas retail electric provider.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
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	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.

PURPA	Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes .
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities .
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
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.
TVA	Tennessee Valley Authority.
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.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by CSPCo.

FORWARD-LOOKING INFORMATION

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

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain operation and maintenance costs.
- Our ability to sell assets at acceptable prices and other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary 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 and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including membership in regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

EXECUTIVE OVERVIEW

Utility Operations Segment Results
Net income from our Utility Operations was $352 million for the third quarter of 2005, representing a decrease of $7 million when compared with net income from our Utility Operations for the third quarter of 2004. The decrease was primarily due to a $26 million after-tax impairment related to our commitment to a plan to retire two units at CSPCo's Conesville Plant. Strong retail and wholesale sales due to warmer weather, customer growth and higher wholesale prices, net of increased fuel costs and higher operating expenses, partially offset the Conesville impairment.

Acquisition
In August 2005, we announced an agreement to purchase the Ceredo Generating Station for approximately $100 million. The Ceredo Generating Station is a natural-gas-fired plant with capacity of 505 megawatts located near Ceredo, West Virginia. This purchase is part of our broad strategy to meet the growing capacity needs of our customer base and reduce reliance on the marketplace. We expect this acquisition to close in the latter part of 2005 or first quarter of 2006.

Dividend Increase
On October 26, 2005, our Board of Directors approved a six percent increase in our quarterly dividend to $0.37 per share from $0.35 per share. We also announced criteria that will be used to make future dividend recommendations to the Board.

Regulatory Activity
West Virginia
In August 2005, APCo and WPCo jointly filed with the Public Service Commission of West Virginia for a $183 million revenue increase. The companies proposed the requested increase to be phased-in over four years. The primary reasons for the request include increasing costs for coal, purchased power and environmental improvement construction projects. A final order is expected in June 2006.

Kentucky
In September 2005, KPCo filed with the Kentucky Public Service Commission for a $65 million revenue increase. The primary reason for the request is to recover increasing costs associated with providing safe and reliable electric service to customers. A final order is expected in April 2006.

Texas
In September 2005, we filed rebuttal testimony in our stranded cost recovery proceeding addressing the issues raised by the various intervenors and PUCT staff. The issues raised were similar to those raised in other nonaffiliated utilities' True-up Proceedings. Texas Restructuring Legislation provides for a PUCT decision within 150 days after filing. Hearings concluded in October 2005 and a final order is expected

in the fourth quarter of 2005.

Fuel Costs

Market prices for coal, natural gas and oil increased dramatically during 2004 and have continued to increase in 2005. These increasing fuel costs are the result of increasing worldwide demand, supply interruptions and uncertainty, anticipation and ultimate promulgation of clean air rules and transportation constraints, as well as other market factors. We manage price and performance risk, particularly for coal, through a portfolio of contracts of varying durations and other fuel procurement and management activities. We have fuel recovery mechanisms for about 45% of our fuel costs in our various jurisdictions. Additionally, about 25% of our fuel is used for off-system sales where prices for our power should allow us to recover our cost of fuel. Accordingly, we should recover approximately 70% of fuel cost increases. The remaining 30% of our fuel costs relate primarily to Ohio and West Virginia customers, where we do not currently have fuel cost recovery mechanisms. Such percentages are subject to change over time based on fuel cost impacts, fuel caps and freezes and changes to the recovery mechanisms at jurisdictions in our individual operating companies. In August 2005, APCo filed in West Virginia to reinstate the suspended fuel cost recovery mechanism. In addition, our Ohio companies will be increasing their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans.

During the third quarter of 2005 as compared to the same period in 2004, higher coal costs reduced gross margins by approximately $22 million and our year-to-date reduction in gross margins related to fuel costs is approximately $119 million. Several major events have impacted fuel costs in 2005. In January, deliveries of coal were restricted due to flooding and restricted shipping on the Ohio River at the Belleville Lock and Dam. Central Appalachian coal deliveries were also affected early in the year by rail transportation limitations resulting in performance issues among coal suppliers, the railroad, and AEP. Some of the suppliers in this region continue to experience performance related issues. The Union Pacific Railroad claimed, in mid-May, a force majeure event due to severe track damage impacting the delivery of Powder River Basin (PRB) coal, which has reduced, and will continue to reduce, PRB coal deliveries by roughly 15% through at least November 2005. Since PRB supplies tend to be lower priced than our average, our delivered coal costs are unfavorably impacted.

Environmental

In June 2005, we revised our environmental investment program that extends through 2010 to a projected investment level of $4.1 billion, from our previous estimate of $3.7 billion. The increase is attributable to continued refinement of our forecast and the ongoing development of estimates for our remaining scrubber program. There could be additional changes in our investment program estimates as we further evaluate and monitor the impact of the Clean Air Interstate Rule and Clean Air Mercury Rule.

In June 2005, we announced five additional locations where we will invest in equipment to continue to improve the environmental performance of our coal-fired power plants including sites in West Virginia, Ohio, Kentucky and Texas. We plan to complete these projects between 2007 and 2010 and are included in both our previous and revised projected investment level discussed above.

Nuclear Licenses

In August 2005, the Nuclear Regulatory Commission approved the renewal of operating licenses for the two generating units at our Cook Plant. The licenses will now expire in 2034 for Unit 1 and 2037 for Unit 2. Based on this renewal, we adjusted our asset retirement obligation liability and related plant asset. We are evaluating the effect of relicensing on current depreciation rates and decommissioning funding. If any changes are necessary, we will need IURC and MPSC approval.

Energy Policy Act of 2005

In August 2005, the President signed the Energy Policy Act of 2005 into law. The Energy Policy Act of 2005 repeals PUHCA, effective February 8, 2006. We believe adoption of the Energy Policy Act of 2005 will end the litigation challenging our merger with CSW. The Energy Policy Act of 2005 provides for tax credits for the development of certain clean coal and emissions technologies and provides federal tax relief in support of our commitment to build IGCC generating units.

Additional Information

For additional information on our strategic outlook, see "Management's Financial Discussion and Analysis of Results of Operations," including "Business Strategy," in our 2004 Annual Report. Also see the remainder of our "Management's Financial Discussion and Analysis of Results of Operations" in this Form 10-Q, along with the Condensed Notes to Condensed Consolidated Financial Statements.

RESULTS OF OPERATIONS

Segments

As outlined in our 2004 Annual Report, our business strategy and the core of our business are to focus on domestic electric utility operations. Our previous decision that we no longer sought business interests outside of the footprint of our domestic core utility assets led us to embark on a divestiture of such noncore assets. Major asset divestitures included the sale in 2004 of two generating plants in the UK, LIG and Jefferson Island Storage & Hub, and the sale in January 2005 of a 98% interest in the HPL assets. Consequently, our Investments segments generally are of significance only to previous periods.

Our on-going segments and their related business activities are as follows:

Utility Operations

- Domestic generation of electricity for sale to retail and wholesale customers.
- Domestic electricity transmission and distribution.

Investments - Other

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

  Four IPPs were sold during 2004.

AEP Consolidated Results

Our consolidated Net Income for the three and nine months periods ended September 30, 2005 and 2004 was as follows (Earnings and Weighted Average Shares Outstanding in millions):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2005		2004		2005		2004	
	Earnings	EPS	Earnings	EPS	Earnings	EPS	Earnings	EPS
Utility Operations	$ 352	$ 0.91	$ 359	$ 0.91	$ 952	$ 2.45	$ 847	$ 2.14
Investments - Other	28	0.07	89	0.22	32	0.08	89	0.22
All Other (a)	(5)	(0.01)	(9)	(0.02)	(45)	(0.12)	(43)	(0.11)
Investments - Gas Operations (b)	(10)	(0.03)	(27)	(0.07)	(2)	-	(41)	(0.10)
Income Before Discontinued Operations	365	0.94	412	1.04	937	2.41	852	2.15
Investments - Gas Operations	-	-	(3)	-	-	-	(2)	-
Investments - UK Operations	2	-	120	0.30	(3)	(0.01)	56	0.14
Investments - Other	20	0.05	1	-	29	0.08	6	0.01
Discontinued Operations, Net of Tax	22	0.05	118	0.30	26	0.07	60	0.15
Net Income	$ 387	$ 0.99	$ 530	$ 1.34	$ 963	$ 2.48	$ 912	$ 2.30
Weighted Average Basic Shares Outstanding		389		396		389		396

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

(b) We sold 98% of our remaining gas operations in January 2005.

Third Quarter of 2005 Compared to Third Quarter of 2004

Income Before Discontinued Operations decreased $47 million to $365 million in the third quarter of 2005 compared to the third quarter of 2004.

For the third quarter of 2005, our Utility Operations earnings decreased $7 million from the third quarter of the previous year primarily due to higher fuel and operating costs and an impairment related to our commitment to a plan to retire two units at our Conesville Plant, partially offset by load and customer growth in all sectors, an increase in off-system sales volumes and margins and Ohio and Texas carrying cost accruals.

Losses before discontinued operations from our Gas Operations for the third quarter of 2005 decreased $17 million from the third quarter of 2004 due to the January 2005 sale of a 98% controlling interest in HPL resulting in decreased operations, maintenance and interest expenses.

Income before discontinued operations from our Investments - Other decreased $61 million from the third quarter of 2004 primarily due to the prior year gain on the sales of our South Coast Power Limited equity investment and three IPPs.

Average basic shares outstanding decreased to 389 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program, which began in March 2005 and ended in May 2005.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Income Before Discontinued Operations increased $85 million to $937 million for the nine months ended September 30, 2005.

For the nine months ended September 30, 2005, our Utility Operations earnings increased $105 million from the same nine month period of the previous year driven primarily by favorable weather and load growth, the Centrica earnings sharing payments received in March 2005 and Ohio and Texas carrying cost accruals. These favorable changes are partially offset by higher fuel costs.

The income before discontinued operations from our Investments - Other decreased $57 million in 2005. This decrease is primarily due to the prior year gain on the sales of our South Coast Power Limited equity investment and three IPPs.

Losses before discontinued operations from our Gas Operations decreased $39 million from the same nine month period of the previous year reflecting favorable results for one month of HPL's operations in 2005 compared with a loss for the nine months of HPL's operations in the prior year. We sold a 98% controlling interest in HPL in January 2005, resulting in decreased operations, maintenance and depreciation expenses as well as decreased interest charges.

Average basic shares outstanding decreased to 389 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program, which began in March 2005 and ended in May 2005.

Our results of operations by operating segment are discussed below.

Utility Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
	(in millions)			
Revenues	$ 3,214	$ 2,950	$ 8,496	$ 8,097

Fuel and Purchased Power	1,197	1,032	3,058	2,631
Gross Margin	2,017	1,918	5,438	5,466
Depreciation and Amortization	328	322	963	940
Other Operating Expenses	1,052	922	2,866	2,804
Operating Income	637	674	1,609	1,722
Other Income (Expense), Net	49	9	253	35
Interest Expense and Preferred Stock Dividend Requirements	145	152	445	479
Income Taxes	189	172	465	431
Income Before Discontinued Operations	$ 352	$ 359	$ 952	$ 847

Summary of Selected Sales Data
For Utility Operations
For the Three and Nine Months Ended September 30, 2005 and 2004

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
Energy Summary	(in millions of KWH)			
Retail:				
Residential	14,152	12,002	37,332	35,169
Commercial	10,900	10,070	29,205	28,240
Industrial	13,380	13,052	39,633	38,227
Miscellaneous	683	857	1,967	2,406
Total Retail	39,115	35,981	108,137	104,042
Texas Retail and Other	114	280	504	802
Total	39,229	36,261	108,641	104,844
Wholesale	14,198	17,629	38,971	45,124
Texas Wires Delivery	8,093	7,691	20,348	19,431

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact weather has on results of operations. Cooling degree days and heating degree days in our service territory for the quarter and year-to-date periods ended September 30, 2005 and 2004 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
Weather Summary	(in degree days)			
Eastern Region				
Actual - Heating	1	1	1,940	2,033

Normal - Heating (a)	7	7	1,995	1,993
Actual - Cooling	835	553	1,122	869
Normal - Cooling (a)	674	679	955	960
Western Region (b)				
Actual - Heating	0	0	795	913
Normal - Heating (a)	2	2	1,007	1,013
Actual - Cooling	1,523	1,178	2,225	1,867
Normal - Cooling (a)	1,397	1,398	2,059	2,058

(a) Normal Heating/Cooling represents the 30-year average of degree days.
(b) Western Region statistics represent PSO/SWEPCo customer base only.

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005
Income Before Discontinued Operations
(in millions)

Third Quarter of 2004		$ 359
Changes in Gross Margin:		
Retail Margins	120	
Texas Supply	(61)	
Transmission Revenues	(20)	
Off-system Sales	69	
Other Revenues	(9)	
Total Change in Gross Margin		99
Changes in Operating Expenses and Other:		
Maintenance and Other Operation	(67)	
Asset Impairments and Other Related Charges	(39)	
Depreciation and Amortization	(6)	
Taxes Other Than Income Taxes	(24)	
Other Income (Expense), Net	40	
Interest Expense	7	
Total Change in Operating Expenses and Other		(89)
Income Taxes		(17)
Third Quarter of 2005		$ 352

Income from Utility Operations decreased $7 million in 2005 compared to 2004.

The major components of our change in gross margin were as follows:

- Retail Margins in our utility business were $120 million higher than last year. The primary driver of this increase was a 12% increase in volume attributable to load growth in residential and commercial classes as well as favorable weather in 2005. This retail margin increase was partially offset by higher delivered fuel costs of approximately $22 million, which primarily relates to our utilities in the East with inactive fuel clauses.
- Our Texas Supply business had a $61 million decrease in gross margin as a result of the sale of a majority of our nonnuclear Texas generation assets in the third quarter of 2004 and STP in May 2005.
- Transmission Revenues decreased $20 million primarily due to the loss of through and out rates as mandated by the FERC partially offset by the addition of SECA rates.
- Margins from Off-system Sales for 2005 were $69 million higher than 2004 primarily due to an increase in volume, favorable price margins and favorable optimization activity.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses increased $67 million. Approximately $22 million of the increase is due to timing of maintenance projects experienced in the third quarter of 2005 as compared to the same period in 2004. Additionally, in 2005 we incurred $13 million of maintenance costs related to major storms. Also, $32 million of the increase relates to increased generation expense, including environmental consumables and allowances, due to strong retail and wholesale sales and capacity requirements in 2005.
- Asset Impairments and Other Related Charges were $39 million in 2005 due to our commitment to a plan in September to retire two units at our Conesville Plant. In September, we formally requested permission from PJM to retire the two units effective December 29, 2005. We received preliminary approval on October 21, 2005.
- Taxes Other Than Income Taxes increased $24 million primarily due to a $15 million increase in property taxes related to increased property values.
  - $15 million related to the recognition of carrying costs by TCC on its net stranded generation costs and its capacity auction true-up asset.
  - $10 million related to the establishment of regulatory assets for carrying costs on environmental capital expenditures and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
  - $17 million related to increased interest income and increased AFUDC due to extensive construction activities occurring in 2005.

See “Income Taxes” section below for discussion of fluctuations related to income taxes.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Reconciliation of Nine Months Ended September 30, 2004 to Nine Months Ended September 30, 2005
Income Before Discontinued Operations
(in millions)

Nine Months Ended September 30, 2004	$	847

Changes in Gross Margin:		
Retail Margins	59	
Texas Supply	(117)	
Transmission Revenues	(71)	
Off-system Sales	103	
Other Revenues	(2)	
Total Change in Gross Margin		(28)
Changes in Operating Expenses and Other:		
Asset Impairments and Other Related Charges	(39)	
Depreciation and Amortization	(23)	
Taxes Other Than Income Taxes	(23)	
Other Income (Expense), Net	218	
Interest Expense	34	
Total Change in Operating Expenses and Other		167
Income Taxes		(34)
Nine Months Ended September 30, 2005		$ 952

Income from Utility Operations increased $105 million to $952 million in 2005. The key driver of the increase was a $218 million increase in Other Income (Expense), Net, partially offset by a $28 million decrease in gross margin, a $39 million increase in asset impairments and a $34 million increase in income taxes.

The major components of our change in gross margin were as follows:

- Overall Retail Margins in our utility business were $59 million higher than last year. The primary driver of this increase was continued customer growth and usage in our residential and commercial classes. This load growth was partially offset by higher delivered fuel costs of approximately $119 million, of which the majority relates to our East companies with inactive fuel clauses.
- Our Texas Supply business had a $117 million decrease in gross margin due to the sale of a majority of our nonnuclear Texas generation assets in the third quarter of 2004 and STP in May 2005.
- Transmission Revenues decreased $71 million primarily due to the loss of through and out rates as mandated by the FERC partially offset by the addition of SECA rates.
- Margins from Off-system Sales for 2005 were $103 million higher than 2004 primarily due to increased volume and favorable price margins.

Utility Operating Expenses and Other changed between years as follows:

- Asset Impairments and Other Related Charges increased $39 million due to our commitment to a plan in September to retire two units at our Conesville Plant. In September, we formally requested permission from PJM to retire the two units effective December 29, 2005. We received preliminary approval on October 21, 2005.
- Other Income (Expense), Net increased $218 million primarily due to the following:
  - $112 million resulting from the receipt of revenues related to the earnings sharing agreement

    with Centrica as stipulated in the purchase and sale agreement from the sale of our REPs in 2002. Agreement was reached with Centrica in March 2005 resolving disputes on how such amounts are to be calculated.
  - $41 million related to the establishment of regulatory assets for carrying costs on environmental capital expenditures and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
  - $32 million related to increased interest income and increased AFUDC due to extensive construction activities occurring in 2005.
  - $30 million related to the recognition of carrying costs by TCC on its net stranded generation costs and its capacity auction true-up asset.
- Interest Expense decreased $34 million due to the refinancing of higher coupon debt and the retirement of debt in 2004 and in the first nine months of 2005.

See "Income Taxes" section below for discussion of fluctuations related to income taxes.

Investments - Other

Third Quarter of 2005 Compared to Third Quarter of 2004

Income before discontinued operations from our Investments - Other segment decreased by $61 million in 2005 primarily due to the gain recorded in 2004 related to the third quarter sale of three of our IPP investments and our 50 percent interest in South Coast Power Limited.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Income before discontinued operations from our Investments - Other segment decreased by $57 million in 2005 primarily due to the gain recorded in 2004 related to the third quarter sale of three of our IPP investments and our 50 percent interest in South Coast Power Limited.

Other

Parent

Third Quarter of 2005 Compared to Third Quarter of 2004

Our parent company's loss for the third quarter of 2005 decreased $4 million in comparison to the third quarter of 2004 due to lower interest expense in 2005 primarily related to the $550 million senior unsecured notes redemption in April 2005.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Our parent company's loss for the nine months ended September 30, 2005 increased $2 million in comparison to the nine months ended September 30, 2004 due to lower interest income related to the repayment of intercompany debt associated with the sale of HPL, partially offset by lower interest expense due to lower short-term debt borrowings in 2005 and savings from the redemption of $550 million senior unsecured notes in April 2005.

Investments - Gas Operations and UK Operations

Third Quarter of 2005 Compared to Third Quarter of 2004

Our $10 million net loss from Gas Operations before discontinued operations compares with a $27 million loss recorded in the third quarter of 2004. The improvement is due to the sale of a 98% controlling interest in HPL in January 2005, offset in part by the settlement of the Bank of Montreal litigation matter (see "Significant Matters""Litigation" section of Management's Financial Discussion and Analysis of Results of Operations).

Income included in discontinued operations from our Investments - UK Operations segment was $2 million in 2005 as compared to income of $120 million in 2004 due to the gain on the sale of substantially all operations and assets within our Investments - UK Operations segment recognized in July 2004.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Our $2 million net loss from Gas Operations before discontinued operations compares with a $41 million loss recorded in the nine months ended September 30, 2004. Due to the sale of a 98% controlling interest in HPL in January 2005, current year results include only one month of HPL's operations compared to nine months of HPL's operations in the prior year.

Losses included in discontinued operations from our Investments - UK Operations segment were $3 million in 2005 as compared to income of $56 million in 2004 due to the gain related to the sale of substantially all operations and assets within our Investments - UK Operations segment in July 2004. The current period amount represents purchase price true-up adjustments made during the first quarter of 2005 related to the 2004 sale.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 34.9% and 33.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes.

The effective tax rates for the nine months ended September 30, 2005 and 2004 were 33.3% and 34.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, energy production credits, amortization of investment tax credits and state income taxes.

FINANCIAL CONDITION

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

Capitalization ($ in millions)

	September 30, 2005		December 31, 2004	
Common Shareholders' Equity	$ 8,985	43.2%	$ 8,515	40.6%
Cumulative Preferred Stock	61	0.3	61	0.3
Cumulative Preferred Stock (Subject to Mandatory Redemption)	-	-	66	0.3
Long-term Debt, including amounts due within one year	11,742	56.4	12,287	58.7
Short-term Debt	15	0.1	23	0.1
Total Capitalization	$ 20,803	100.0%	$ 20,952	100.0%

In March 2005, we repurchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share. The 12.5 million shares repurchased under the program were subject to a contingent purchase price adjustment based on the actual purchase prices paid for the common stock during the program period. Based on this adjustment, our actual stock purchase price averaged $34.18 per share.

In April 2005, we redeemed $550 million of parent company senior unsecured notes.

In August 2005, we issued 8.4 million shares of common stock as part of the settlement of forward purchase contracts embedded in equity units issued in June 2002. The senior notes associated with the equity units were remarketed in June 2005 with the proceeds held by a trustee for settlement of the forward purchase contracts on behalf of the original equity unit holders. With the issuance of the shares of common stock, we received $345 million from the trustee on behalf of the holders.

As a consequence of the capital changes during the first nine months of 2005, our ratio of debt to total capital decreased from 59.1% to 56.5% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to preserving an adequate liquidity position through the effective management of external financing commitments, appropriate balances of cash and other temporary investments on hand, our operational cash management and our investing activities.

Credit Facilities

We manage our liquidity, in part, by maintaining adequate external financing commitments. We had an available liquidity position, at September 30, 2005, of approximately $3.4 billion as illustrated in the table below.

	Amount (in millions)	Maturity
Commercial Paper Backup:		

Revolving Credit Facility	$	1,000	May 2007
Revolving Credit Facility		1,500	March 2010
Letter of Credit Facility		200	September 2006
Total		2,700	
Cash and Cash Equivalents		849	
Total Liquidity Sources		3,549	
Less: AEP Commercial Paper Outstanding		-(a)	
Letters of Credit Outstanding		150	
Net Available Liquidity at September 30, 2005	$	3,399	

(a) Amount does not include JMG commercial paper outstanding in the amount of $15 million. This commercial paper is specifically associated with the Gavin scrubber and does not reduce AEP's available liquidity. The JMG commercial paper is supported by a separate letter of credit facility not included above.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At September 30, 2005, this percentage was 53.5%. Nonperformance of these covenants could result in an event of default under these credit agreements. At September 30, 2005, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the amounts outstanding thereunder payable.

Our $1 billion revolving credit facility, which matures in May 2007, generally prohibits new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under this facility if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper. Under the $1.5 billion revolving credit facility, which matures in March 2010, we may borrow despite a material adverse change.

Under an SEC order, we and our utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts us and our 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, 2005, we were in compliance with this order. The Energy Policy Act of 2005 repeals PUHCA effective February 8, 2006. With repeal, compliance with this order will no longer be necessary. However, new regulatory requirements of the FERC could replace or modify this order.

Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC or state commission authorized limits. At September 30, 2005, we had not exceeded the SEC or state commission authorized limits.

Credit Ratings

Moody's upgraded our short-term and long-term ratings during September 2005. We are currently on a stable outlook by Moody's.

Our current ratings by the major agencies are as follows:

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

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

Cash Flow

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

	Nine Months Ended September 30,	
	2005	2004
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 320	$ 778
Cash Flows From (Used For):		
Operating Activities	1,587	2,278
Investing Activities	12	(33)
Financing Activities	(1,070)	(2,089)
Net Increase in Cash and Cash Equivalents	529	156
Cash and Cash Equivalents at End of Period	$ 849	$ 934
Other Temporary Cash Investments	$ 73	$ 529

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provide necessary working capital and help us 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 our other subsidiaries that are not participants in the Nonutility Money Pool. As of September 30, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. At September 30, 2005, we had no outstanding short-term borrowings supported by the revolving credit facilities. JMG had commercial paper outstanding in the amount of $15 million. This commercial paper is specifically associated with the Gavin scrubber and is not supported by our credit facilities. The maximum amount of commercial paper outstanding during the nine months ended September 30, 2005 was $25 million. The weighted-average interest rate for our commercial paper during the first nine months of 2005 was 2.5%.

We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding alternatives are arranged. Sources of long-term funding include issuance of common stock, preferred stock or long-term debt and sale-leaseback or leasing agreements.

In addition to our Cash and Cash Equivalents, we have Other Temporary Cash Investments on hand that we use to manage and maintain our liquidity.

Operating Activities

	Nine Months Ended September 30,	
	2005	**2004**
	(in millions)	
Net Income	$ 963	$ 912
Plus: (Income) From Discontinued Operations	(26)	(60)
Income from Continuing Operations	937	852
Noncash Items Included in Earnings	1,039	1,267
Changes in Assets and Liabilities	(389)	159
Net Cash Flows From Operating Activities	$ 1,587	$ 2,278

The key drivers of the decrease in cash from operations for the first nine months of 2005 are the Pension Contributions of $306 million and an increase in our under-recovered fuel of $183 million.

2005 Operating Cash Flow

Net Cash Flows From Operating Activities were approximately $1.6 billion for the first nine months of 2005. We produced Income from Continuing Operations of $937 million during the period. Income from Continuing Operations for the period included noncash expense items primarily for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. We made contributions of $306 million to our pension trust fund. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are a $204 million cash increase from Accounts Payable and an increase in the balance of Taxes Accrued of $118 million. Cash increased related to Accounts Payable due to higher fuel and allowance acquisition costs not paid at September 30, 2005. Taxes Accrued increased due to the difference between the recording of the current federal income tax liability, the timing of required estimated payments and the receipt of a prior year federal income tax refund. Our consolidated tax group paid a total of $217 million in federal income taxes, net of refunds, during the first nine months of 2005.

2004 Operating Cash Flow

Net Cash Flows From Operating Activities were approximately $2.3 billion for the first nine months of 2004. We produced Income from Continuing Operations of $852 million during the period. Income from Continuing Operations for the period included noncash items of $1.1 billion for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. There was a current period favorable impact for a net $89 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The most significant change in other activity in the asset and liability accounts was an increase in Taxes Accrued of $388 million. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since our consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

Investing Activities

	Nine Months Ended September 30,	
	2005	**2004**
	(in millions)	
Construction Expenditures	$ (1,610)	$ (1,047)
Acquisition of Waterford Plant	(218)	-
Change in Other Temporary Cash Investments, Net	99	28
Investment in Discontinued Operations, Net	-	(59)
Purchases of Investments	(3,342)	(425)
Proceeds from the Sale of Investments	3,445	274
Proceeds from Sale of Assets	1,599	1,202
Other	39	(6)
Net Cash Flows From (Used For) Investing Activities	$ 12	$ (33)

Net Cash Flows From Investing Activities were $12 million in 2005 primarily due to proceeds from the sale of HPL and STP in 2005 significantly offset by our Construction Expenditures. Our Construction Expenditures include planned environmental, transmission and distribution investments. Our remaining Construction Expenditures for 2005 are estimated to be approximately $900 million.

We purchase auction rate securities and variable rate demand notes with cash available for short-term investment. During the first nine months of 2005, we purchased $3.3 billion of investments and received $3.4 billion of proceeds from their sale, which included the sale of our investments held at December 31, 2004, as reflected above in the Change in Other Temporary Cash Investments, Net line.

Net Cash Flows Used For Investing Activities were $33 million in 2004 primarily due to Construction Expenditures being offset by proceeds from the sales of the Pushan Power Plant in China and LIG Pipeline Company. The sales were part of our announced plan to divest noncore investments and assets.

We forecast $3.3 billion of construction expenditures for 2006. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital.

Financing Activities

	Nine Months Ended September 30,	
	2005	**2004**
	(in millions)	
Issuance of Common Stock	$ 393	$ 13
Repurchase of Common Stock	(427)	-
Issuance/Retirement of Debt, net	(562)	(1,683)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid on Common Stock	(408)	(415)
Net Cash Flows Used For Financing Activities	$ (1,070)	$ (2,089)

Net Cash Flows Used For Financing Activities in 2005 were approximately $1.1 billion. During the first nine months of 2005, we repurchased common stock and reduced outstanding long-term debt using the proceeds from the sale of HPL and from the conversion of the equity units to common stock. Our subsidiaries retired $66 million of cumulative preferred stock.

Net Cash Flows Used For Financing Activities were approximately $2.1 billion in 2004. During 2004, we retired debt using proceeds from the sale of assets and cash from operating activities.

In October 2005, CSPCo issued $250 million of 5.85% Senior Notes, Series F, due in October 2035.

Off-balance Sheet Arrangements

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current policy restricts the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. Our off-balance sheet arrangements have not changed significantly from year-end. For complete information on each of these off-balance sheet arrangements see the "Minority Interest and Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2004 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end other than the issuances and retirements discussed in "Cash Flow""Financing Activities" above.

SIGNIFICANT MATTERS

Texas Regulatory Activity

Texas Restructuring

The principal remaining component of the stranded cost recovery process in Texas is the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items including carrying costs in TCC's true-up filing under the Texas Restructuring Legislation. The PUCT approved TCC's request to file its True-up Proceeding after the sales of its interest in STP, with only the ownership interest in Oklaunion remaining to be settled. On May 19, 2005, the sales of TCC's interest in STP closed. On May 27, 2005, TCC filed its true-up request seeking recovery of $2.4 billion of net stranded costs and other true-up items which it believes the Texas Restructuring Legislation allows. TCC's request includes unrecorded equity carrying costs through May 27, 2005 and amounts for stranded costs that we have previously written off (principally, a $238 million provision for a probable depreciation adjustment recorded in December 2004 based on a methodology approved by the PUCT in a nonaffiliated utility's true-up order). The PUCT hearing concluded on October 4, 2005. It is anticipated that the PUCT will issue a final order in the fourth quarter of 2005.

TCC continues to accrue carrying costs on its net true-up regulatory asset at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on an assumed cost-of-money benefit for accumulated deferred federal income taxes retroactively applied to January 1, 2004. In the first nine months of 2005, TCC began to accrue carrying costs based on this order. Through September 30, 2005, TCC has computed carrying costs of $509 million, of which TCC has recognized $332 million to-date. The equity component of the carrying costs, which totals $177 million through September 30, 2005, will be recognized in income as collected.

In TCC's True-up Proceeding, parties have recommended that the PUCT reduce TCC's carrying cost rate to an amount that ranged from 7.5% to the combined rate that was settled upon in TCC's wires rate proceeding which included a cost of debt of 5.7%. If the PUCT ultimately determines that a lower rate should be used by TCC to calculate carrying costs on its stranded cost balance, a portion of carrying costs previously recorded would have to be reversed and it would have an adverse impact on future results of operations and cash flows. Based upon a range of debt rates from 7.5% to 5.7%, through September 30, 2005, such reversal would range from $28 million to $107 million, of which $6 million to $22 million would apply to amounts accrued in 2005.

When the True-up Proceeding is completed, TCC intends to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in its regulated transmission and distribution (T&D) rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

We believe that our filed request for recovery of $2.4 billion of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation and that our $1.6 billion recorded net true-up regulatory asset, inclusive of carrying costs at September 30, 2005, is probable of recovery at this time. However, other parties have contended that all or material amounts of our net stranded costs and/or wholesale capacity auction true-up amounts should not be recovered. To the extent decisions of the PUCT in TCC's True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated utilities, additional provisions for material disallowances and reductions of the net true-up regulatory asset, including recorded carrying costs, are possible. Such disallowances would have a material adverse effect on future results of operations, cash flows and possibly financial condition.

Ohio Regulatory Activity

Ohio Restructuring

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for possible additional annual generation rate increases of up to an average of 4% per year based on the Ohio Companies supporting the need for additional revenues for specified costs. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. Pretax earnings increased by $6 million for CSPCo and $35 million for OPCo in the first nine months of 2005 as a result of implementing this provision of the RSP.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding its approval of the RSP. On March 23, 2005, the PUCO denied all applications for rehearing. In the second quarter of 2005, two intervenors filed separate appeals to the Ohio Supreme Court. One of those appeals has been withdrawn. If the RSP order is determined on appeal to be illegal under the restructuring legislation, it would have an adverse effect on results of operations, cash flows and possibly financial condition. Although we believe that the RSP plan is legal and we intend to defend vigorously the PUCO's order, we cannot predict the ultimate outcome of the pending litigation.

Integrated Gasification Combined Cycle (IGCC) Power Plant

On March 18, 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new approximately 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $24 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover construction-financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their RSP. In Phase 3, which begins when the plant enters commercial operation and runs through the operating life of the plant, the Ohio companies would recover, or refund, in distribution rates any difference between the Ohio companies' market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected $1.2 billion cost of the plant along with fuel, consumables and replacement power. As of September 30, 2005, we have deferred $6 million of pre-construction IGCC costs. These costs primarily relate to an agreement with GE Energy and Bechtel Corporation to begin the front-end engineering design process.

Monongahela Power Company

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, we agreed to terms of a transaction, which includes the transfer to CSPCo of Monongahela Power's Ohio customer base and the assets that serve those customers for an estimated sales price of approximately $45 million. The net assets are being acquired at net book value. The sale price will be adjusted based on book values of the acquired assets and certain related liabilities at the closing date. In addition, CSPCo will pay $10 million to compensate Monongahela Power for its termination of certain generation cost recovery litigation in Ohio. CSPCo is proposing that the $10 million payment will be recorded as a regulatory asset and recovered with a carrying cost from large commercial and industrial customers in the Monongahela Power Ohio service territory over approximately 5 years.

Also included in the proposed transaction is a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007. CSPCo is proposing that beginning June 1, 2007, it will acquire power on the market to meet the needs of the acquired customers through December 31, 2008 (the end of the RSP period). CSPCo has proposed a generation surcharge to be applied to all of its customers to recover the difference between the cost of power included in its generation rates and the higher Allegheny and subsequent market-based purchased power cost to meet the power requirements of the customers acquired from Monongahela Power through the end of the RSP period. CSPCo is proposing to institute a true-up mechanism with over/under-recovery deferral accounting for any difference between the surcharge recoveries and the actual cost differential. CSPCo has also requested permission to defer with a carrying cost incremental costs associated with the transaction for future recovery in the next CSPCo distribution rate case. Hearings at the PUCO were held in September 2005. If the transaction is approved by the PUCO, we expect to close the proposed transaction in December 2005.

Oklahoma Regulatory Activity

PSO Rate Review

PSO has been involved in a commission staff-initiated base rate review before the OCC which began in 2003. In March 2005, a settlement was negotiated and approved by the ALJ. The settlement provides for a $7 million annual base revenue reduction, offset by a $6 million reduction in annual depreciation expense and recovery through fuel revenues of certain transmission expenses previously recovered in base rates. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. The settlement also provides for recovery over 24 months of $9 million of deferred fuel costs associated with a renegotiated coal transportation contract and the continuation of a $12 million vegetation management rider, both of which are earnings neutral. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC issued an order approving the stipulation on May 2, 2005, and new base rates were implemented in June 2005. We anticipate that this order will favorably impact results of operations and cash flows beginning in 2006.

PSO Fuel and Purchased Power and its Potential Impact on the AEP East Companies

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO offered to the OCC to collect those reallocated costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. Subsequently, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices and off-system sales margin sharing between AEP East and AEP West companies for the year 2002. On July 25, 2005, the OCC Staff and two intervenors filed testimony in which they quantified an alleged improper allocation of off-system sales margins between AEP East and AEP West companies. Their overall recommendations would result in an increase in off-system sales margins and thus, a reduction in PSO's recoverable fuel costs through June 2005 of an amount between $38 million and $47 million. PSO does not agree with the intervenors' and the OCC Staff's recommendations and will defend vigorously its position. In addition, PSO believes the amounts of such alleged improper allocations are significantly overstated.

As noted in the 2004 Annual Report, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. On September 29, 2005, the United States District Court, Western District of Texas, issued an order in the TNC fuel proceeding, preempting the PUCT from deciding this same allocation issue in Texas. Based on the position taken by the Federal court in Texas, it would appear that OCC would be preempted from disallowing PSO's fuel costs in Oklahoma based on an alleged improper off-system sales margin allocation under a FERC jurisdictional allocation agreement. If the OCC or another party files a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies due to a reallocation of off-system sales margins between the AEP East and AEP West companies.

On June 10, 2005, the OCC decided to have its staff conduct a prudence review of PSO's fuel and purchased power practices for 2003.

Management is unable to predict the ultimate effect of these proceedings on revenues, results of operations, cash flows and financial condition.

Virginia and West Virginia Regulatory Activity

APCo Virginia Environmental and Reliability Costs

In April 2004, the Virginia Electric Restructuring Act was amended to include a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and T&D system reliability (E&R) costs prudently incurred after July 1,

2004. On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request represents i) expected costs of environmental controls on coal-fired generators to meet the first phase of the Clean Air Interstate Rule and Clean Air Mercury Rule finalized earlier this year, ii) recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kilovolt transmission line construction and iii) other incremental T&D system reliability costs from July 1, 2004 to June 30, 2006.

In the filing, APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. The recovery factor would have been applied as a 9.18% surcharge to customer bills. APCo had proposed to practice over/under-recovery deferral accounting for the difference between the actual incremental costs incurred and revenue recovered.

Through September 30, 2005, APCo has incurred approximately $13 million of actual incremental E&R costs and has deferred $7 million of such costs for future recovery. APCo did not record $2 million of equity carrying costs that are not recognized until collected. Additionally, E&R costs of $4 million represented previously capitalized interest that was duplicative of the carrying costs.

On October 14, 2005, the Virginia SCC denied APCo's request to place in effect, on an interim basis subject to refund, its proposed cost recovery surcharge. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the February 7, 2006 public hearing in this case. The Virginia SCC also ruled in this order that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, according to this order, APCo may update its request to reflect additional incurred costs and/or present additional evidence. If the Virginia SCC denies recovery of any portion of the net incremental actual amounts deferred to date, it would adversely affect future results of operations and cash flows.

APCo and WPCo West Virginia Rate Case

On August 26, 2005, APCo and WPCo collectively filed an application with the Public Service Commission of West Virginia seeking an initial increase in their retail rates of approximately $82 million. The initial increase included approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism which accounted for $72 million of the initial increase and approval to implement a system reliability tracker which accounted for $10 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins and transmission items. In addition, APCo and WPCo requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining proposed supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively. It is expected that the proposed rates will become effective on June 23, 2006 under West Virginia law. APCo has a regulatory liability of $52 million of pre-suspension, previously over-recovered ENEC costs which it is proposing to apply plus a carrying cost in the future to any under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism. Management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

Kentucky Regulatory Activity

KPCo Rate Filing

On September 26, 2005, KPCo filed a request with the Kentucky Public Service Commission to increase base rates by approximately $65 million to recover increasing costs. A final order is expected in April 2006. We are unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism, SECA, became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. SECA transition rates are in effect through March 31, 2006. The FERC has set the SECA rate issue for hearing and indicated that the SECA rates are being recovered subject to refund. We recognized net SECA revenues of $36 million and $93 million in the third quarter and first nine months of 2005, respectively. In addition, we recognized $11 million of net SECA revenues in December 2004. Intervenors in that proceeding are objecting to the SECA rates and our method of determining those rates. Management is unable to determine the probable outcome of the FERC's SECA rate proceeding.

In a March 31, 2005 FERC filing, we proposed an increase in the revenue requirements and rates for transmission service, and certain ancillary services in the AEP zone of PJM. The customers receiving these services are the AEP East companies, municipal and cooperative wholesale entities and retail customers that exercise retail choice that have load delivery points in the AEP zone of PJM. As proposed, the transmission service rates will increase in two steps, first to reflect an increase in the revenue requirements, and then to reflect the loss of revenues from the discontinuance of SECA transition rates on April 1, 2006. On May 31, 2005, the FERC accepted the filing, set the issues for hearing, and suspended the effective date of the first increase in OATT rates until November 1, 2005, subject to refund with interest if lower rates are eventually approved. The FERC accepted the two-step increase concept, such that the transmission rates will automatically increase on April 1, 2006, if the SECA revenues cease to be collected, and to the extent that replacement rates are not established. In a separate proceeding, at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional service provided by high voltage facilities they own that benefit customers throughout PJM. On September 30, 2005, AEP and a nonaffiliated utility (Allegheny Power) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime.

As of September 30, 2005, SECA transition rates have not fully compensated the AEP East companies for their lost T&O revenues. Management is unable to predict whether SECA rates and, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone will be sufficient to replace the SECA transition rate revenues. In addition, we are unable to predict whether the effect of the loss of transmission revenues will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If, (i) the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006,

(ii) AEP zonal transmission rates are not sufficiently increased by the FERC after March 31, 2006 to replace the lost T&O/SECA revenues, (iii) the FERC's review of our current SECA rate results in a rate reduction which is subject to refund, or (iv) any increase in the AEP East companies' transmission costs from the loss of transmission revenues are not fully recovered in retail and wholesale rates on a timely basis, and (v) if the FERC does not approve a new rate within PJM, future results of operations, cash flows and financial condition would be adversely affected.

Litigation

We continue to be involved in various litigation described in the "Significant Factors - Litigation" section of Management's Financial Discussion and Analysis of Results of Operations in our 2004 Annual Report. The 2004 Annual Report should be read in conjunction with this report in order to understand other litigation that did not have significant changes in status since the issuance of our 2004 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition. Other matters described in the 2004 Annual Report that did not have significant changes during the first nine months of 2005, that should be read in order to gain a full understanding of our current litigation include: (1) Coal Transportation Dispute, (2) Shareholders' Litigation, (3) Potential Uninsured Losses, (4) Enron Bankruptcy, (5) Natural Gas Markets Lawsuits and (6) Cornerstone Lawsuit. Additionally, refer to the Commitments and Contingencies footnote in our Condensed Notes to Condensed Consolidated Financial Statements for further discussion of these matters.

New Source Review Litigation

See discussion of New Source Review Litigation within "Significant Factors - Environmental Matters."

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and filed a petition for review of this Initial Decision, which the SEC has granted.

We believe the repeal of PUHCA will end litigation challenging our merger with CSW. All parties to the proceeding have filed motions with the SEC supporting dismissal of the proceeding upon repeal of the PUHCA in February 2006.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts. We claimed that BOM owed us at least $41 million related to previously recorded receivables on which we held approximately $20 million of credit collateral. In September 2005, we reached a settlement, subject to a confidentiality clause, with BOM without material impact on results of operations or financial condition.

TEM Litigation

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

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

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

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

On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the New York federal court that the PPA was terminated and (iii) would be pursuing against TEM, and SUEZ-TRACTEBEL S.A. under the guaranty, damages and the full termination payment value of the PPA.

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

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

Texas Commercial Energy, LLP Lawsuit

In July 2003, Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas against us and four of our subsidiaries, ERCOT and a number of nonaffiliated energy companies including TXU, CenterPoint, Texas Genco, Reliant, TECO and Tractebel. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to their fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. In June 2004, the Court dismissed all claims against the AEP companies. TCE appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit. The Fifth Circuit issued its decision in June 2005 and affirmed the lower Court's decision. TCE filed a Petition for Writ of Certiorari with the United States Supreme Court on October 14, 2005. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit against the same defendants and others. Trial is scheduled in the Utility Choice/Cirro Energy case for April 2006. On October 18, 2005, the U.S. District Court heard oral argument on our Motion to Dismiss. We intend to continue to defend vigorously against the allegations in these cases.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the references to a specific heat input value for each Welsh unit.

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

Spent Nuclear Fuel Litigation

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, we, along with a number of nonaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, we filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In January 2003, the U.S. Court of Federal Claims ruled in our favor on the issue of liability. The case was tried in March 2004 on the issue of damages owed to us by the DOE. In May 2004, the U.S. Court of Federal Claims ruled against us and denied damages, ruling that pre-breach and post-breach damages are not recoverable in a partial breach case. In July 2004, we appealed this ruling to the U.S. Court of Appeals for the Federal Circuit. In September 2005, the U.S. Court of Appeals ruled that the trial court erred in ruling that pre-breach damages in a partial breach case are per se not recoverable, but denied us our pre-breach damages on the facts alleged. The Court of Appeals also ruled that the trial court did not err in determining that post-breach damages are not recoverable in a partial breach case, but determined that we may recover our post-breach damages in later suits as the costs are incurred.

Ontario Litigation

In June 2005, we were named as one of 21 defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted NO_x, SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $50 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

Environmental Matters

As discussed in our 2004 Annual Report, there are emerging environmental control requirements that we expect will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on SO_2, NO_x and mercury emissions from coal-fired power plants,

- Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climate change.

This discussion updates certain events occurring in 2005. You should also read the "Significant Factors - Environmental Matters" section within Management's Financial Discussion and Analysis of Results of Operations in our 2004 Annual Report for a description of all environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) the Comprehensive Environmental Response Compensation and Liability Act (Superfund) and state remediation, (4) global climate change, (5) costs for spent nuclear fuel disposal and decommissioning, and (6) Clean Water Act regulation.

Future Reduction Requirements for SO_2, NO_x and Mercury

Regulatory Emissions Reductions

In January 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% each in emissions of SO_2, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the Eastern United States (29 states and the District of Columbia) and make progress toward attainment of the new fine particulate matter and ground-level ozone national ambient air quality standards. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

On March 14, 2005, the Administrator of the Federal EPA signed the final CAIR. The rule includes both a seasonal and annual NO_x control program as well as an annual SO_2 control program. All of the states in which our generating facilities are located will be subject to the seasonal and annual NO_x control programs and the annual SO_2 control program, except for Texas, Oklahoma and Arkansas. Texas will be subject to the annual programs only. Arkansas will be subject to the seasonal NO_x control program only. Oklahoma is not affected by CAIR. In addition, the compliance deadline for Phase I for the NO_x control program has been accelerated to 2009, and will replace any obligations imposed by the NO_x State Implementation Plan (SIP) Call in 2009. On August 24, 2005, the Administrator of the Federal EPA published a proposed rule that includes a federal implementation plan (FIP) to reduce transport of fine particulate matter and ozone, modeled on the final CAIR, and proposes to deny the Section 126 petition filed by the State of North Carolina to require reductions of NO_x and SO_2 from specific facilities in thirteen states, including several AEP facilities. The proposed rule denies North Carolina's petition for action based on its ozone non-attainment area, since the Federal EPA's modeling predicts that this area will be in attainment with the 8-hour standard in 2010. The Federal EPA also proposes to deny the petition based on North Carolina's $PM_{2.5}$ non-attainment areas, based on the reductions prescribed by the FIP, or to withdraw its Section 126 findings with respect to any state that submits a SIP implementing the CAIR requirements.

On March 15, 2005, the Administrator of the Federal EPA signed a final Clean Air Mercury Rule (CAMR) that will permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. The final CAMR imposes a national cap on mercury emissions from coal-fired power plants of 38 tons by 2010 and 15 tons by 2018. On October 21, 2005, the Federal EPA announced its decision to reconsider several issues in connection with the CAMR, including the legal basis for its decision to withdraw the December 2000 finding under Section 112 of the CAA and the impacts associated with the implementation of an emissions cap and trading program.

In April 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include "Best Available Retrofit Technology" (BART) requirements for individual facilities in their SIPs to address regional haze. The requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. On June 15, 2005, the Federal EPA issued its final "Clean Air Visibility Rule" (CAVR). The record for the final rule contains an analysis that demonstrates that for electric generating units subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Therefore, states that adopt the CAIR are allowed to substitute CAIR for controls otherwise required by BART. On July 20, 2005, the Federal EPA also issued a proposed rule detailing the requirements for an emissions trading program that can satisfy the BART requirements for the regional haze program.

The changes in the Federal EPA's final CAIR, CAMR and CAVR have not caused us to significantly revise our estimates of the capital investments necessary to achieve compliance with these requirements. However, the final rules give states substantial discretion in developing their rules to implement these programs and states will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. In addition, the CAIR, CAMR and CAVR have been challenged in the United States Court of Appeals for the District of Columbia. As a result, the ultimate requirements may not be known for several years and may depart significantly from the rules described here. If the final rules are remanded by the court, if states elect not to participate in the federal cap-and-trade programs, and/or if states elect to impose additional requirements on individual units that are already subject to the CAIR, CAVR and/or CAMR, our costs could increase significantly. The cost of compliance could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

New Source Review (NSR) Litigation

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the new source review requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded.

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

In June 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV were already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, the Federal EPA and eight Northeastern states each filed an additional complaint containing the same allegations against the Amos and Conesville plants that the judge disallowed in the pending case. The Northeastern states' complaint has been assigned to the same judge in the U.S. District Court for the Southern District of Ohio. AEP filed an answer to the Northeastern states' complaint and to the Federal EPA's complaint, denying the allegations and stating its defenses.

On June 24, 2005, the United States Court of Appeals for the District of Columbia Circuit issued a decision affirming in part the new source review reform regulations adopted by the Federal EPA in December 2002. The court upheld the Federal EPA's decision to apply an actual-to-future actual emissions, and includes tests utilizing a five-year look back period to establish actual baseline emissions for utilities and a ten-year period for other sources. This excludes increased emissions unrelated to a physical change from the projected emissions and includes emissions associated with demand growth. The court vacated the Federal EPA's adoption of a broad pollution control project exclusion that includes projects that result in a significant collateral emissions increase, and the "clean unit" applicability test, and remanded certain recordkeeping requirements to the Federal EPA.

On August 30, 2005, the United States Court of Appeals for the Fourth Circuit denied the petitions for rehearing filed by the United States and other appellants in the Duke Energy case. On October 13, 2005, the Administrator of the Federal EPA signed a proposed rule that would adopt a test for determining when an emissions increase results from a change at an existing electric utility generating unit under the federal NSR programs that would be consistent with the test adopted and applied by the Fourth Circuit in the Duke Energy case. This would be based on maximum hourly emissions before and after the change. The Federal EPA is also seeking comments on two alternative formulations of the emission increase test. We have filed a Motion in the NSR litigation that asks the Court, among other things, to dismiss the NSR cases on due process grounds based on the statements and admissions the Federal EPA made in promulgating the proposed rule.

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

Emergency Release Reporting

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances that cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to the alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. I&M and the Federal EPA signed a Final Consent Agreement and Final Order related to the Administrative Complaint effective June 30, 2005. I&M paid a $15 thousand penalty and will invest in a supplemental environmental project at the Cook Plant.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCo's Gavin Plant SCR system. The Federal EPA indicated its intent to seek civil penalties. OPCo and the Federal EPA signed a Final Consent Agreement and Final Order related to the Administrative Complaint effective September 30, 2005. OPCo paid a $16 thousand penalty and will invest in a supplemental environmental project at the Gavin Plant.

Carbon Dioxide Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions alleged that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. A notice of appeal to the Second Circuit Court of Appeals has been filed on behalf of all plaintiffs. A briefing schedule has not been established.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2004 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.

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 has certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

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

We have established policies and procedures that allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, senior executives, and other senior financial and operating managers.

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

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

This table provides detail on changes in our MTM asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations	Total
Total MTM Risk Management Contract				

Net Assets (Liabilities) at December 31, 2004	$ 277	$ -	$ (12)	$ 265
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(93)	18	12	(63)
Fair Value of New Contracts When Entered During the Period (b)	2	-	-	2
Net Option Premiums Paid/(Received) (c)	(4)	-	-	(4)
Change in Fair Value Due to Valuation Methodology Changes	-	-	-	-
Changes in Fair Value of Risk Management Contracts (d)	59	1	-	60
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	19	-	-	19
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2005	$ 260	$ 19	$ -	279
Net Cash Flow and Fair Value Hedge Contracts (f)				(64)
Ending Net Risk Management Assets at September 30, 2005				$ 215

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts entered in 2005.

(d) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

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

(f) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed in detail within the following pages.

Detail on MTM Risk Management Contract Net Assets (Liabilities)

As of September 30, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Total
Current Assets	$ 919	$ 390	$ 1,309
Noncurrent Assets	641	274	915
Total Assets	1,560	664	2,224
Current Liabilities	(845)	(362)	(1,207)
Noncurrent Liabilities	(455)	(283)	(738)
Total Liabilities	(1,300)	(645)	(1,945)
Total Net Assets (Liabilities), excluding Hedges	$ 260	$ 19	$ 279

Reconciliation of MTM Risk Management Contracts to Total MTM Risk Management Contract Net Assets (Liabilities)
As of September 30, 2005
(in millions)

	MTM Risk Management Contracts (a)	PLUS: Hedges	Total (b)
Current Assets	$ 1,309	$ 9	$ 1,318
Noncurrent Assets	915	3	918
Total MTM Derivative Contract Assets	2,224	12	2,236
Current Liabilities	(1,207)	(73)	(1,280)
Noncurrent Liabilities	(738)	(3)	(741)
Total MTM Derivative Contract Liabilities	(1,945)	(76)	(2,021)
Total MTM Derivative Contract Net Assets	$ 279	$ (64)	$ 215

(a) Does not include Cash Flow and Fair Value Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Condensed Consolidated Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets (liabilities) provides two fundamental pieces of information.

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
Fair Value of Contracts as of September 30, 2005
(in millions)

	Remainder 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ (18)	$ 68	$ (4)	$ 2	$ -	$ -	$ 48
Prices Provided by Other External Sources - OTC Broker Quotes (a)	75	33	97	30	3	-	238
Prices Based on Models and Other Valuation Methods (b)	(10)	(57)	(33)	16	33	25	(26)
Total	$ 47	$ 44	$ 60	$ 48	$ 36	$ 25	$ 260
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ 9	$ (16)	$ 10	$ -	$ -	$ -	$ 3
Prices Provided by Other External Sources - OTC Broker Quotes (a)	30	6	(7)	-	-	-	29
Prices Based on Models and Other Valuation Methods (b)	(3)	(2)	-	(2)	(4)	(2)	(13)
Total	$ 36	$ (12)	$ 3	$ (2)	$ (4)	$ (2)	$ 19
Total:							
Prices Actively Quoted - Exchange Traded Contracts	$ (9)	$ 52	$ 6	$ 2	$ -	$ -	$ 51
Prices Provided by Other External Sources - OTC Broker Quotes (a)	105	39	90	30	3	-	267
Prices Based on Models and Other Valuation Methods (b)	(13)	(59)	(33)	14	29	23	(39)
Total	$ 83	$ 32	$ 63	$ 46	$ 32	$ 23	$ 279

(a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained