KENTUCKY POWER CO

FORM 10-Q
(Quarterly Report)

Filed 8/4/2005 For Period Ending 6/30/2005

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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 **June 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

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 July 29, 2005
American Electric Power Company, Inc.	384,772,013
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
June 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	Meaning
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.
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.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System’s Nonutility Money Pool.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Oklahoma Corporation Commission.
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.
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 .

SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
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.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- The ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- 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 and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

EXECUTIVE OVERVIEW

Utility Operations Segment Results
Net income from our Utility Operations was $247 million for the second quarter of 2005, representing an increase of $63 million when compared with net income from our Utility Operations for the second quarter of 2004. The increase was due to higher retail and wholesale sales, lower maintenance and other operation expenses, the recognition of carrying costs for our Ohio companies' environmental investments and regional transmission organization expenses and the accrual of carrying costs on our stranded costs in Texas.

The increase in retail sales is due to the continuing effect of customer growth and higher usage across all classes, partially due to warmer weather in the latter part of the second quarter of 2005. The increase in wholesale sales is from higher margins on off-system sales. Partially offsetting these favorable items are higher fuel costs, as further discussed below in the "Fuel Costs" section, and reduced transmission revenues.

Acquisitions
In May 2005, we announced an agreement to purchase the Waterford Energy Center for $220 million. The Waterford Energy Center is a natural-gas-fired plant with capacity of 821 megawatts located in Waterford, Ohio. 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 third quarter of 2005.

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 of Monongahela Power's Ohio customer base and the assets that serve those customers to CSPCo for an estimated sales price of approximately $55 million. The sale price will be adjusted based on book values of the acquired assets and liabilities at the closing date. We anticipate the purchase, subject to regulatory approval, to close late in the fourth quarter of 2005.

Environmental
In June 2005, we revised our environmental investment program that extends from 2004 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. These projects will be completed between 2007 and 2010 and are included in both our previous and revised projected investment level discussed above.

Texas Regulatory Activity

Stranded Cost Recovery

During May 2005, TCC:

- Sold its ownership interest in the South Texas Project (STP) nuclear plant for approximately $314 million and the assumption of liabilities of approximately $22 million;

- Received a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closing of the sale of TCC's ownership interest in Oklaunion, which is still in litigation; and
- Submitted its true-up filing to the PUCT for a final determination of stranded costs and other true-up amounts.

Texas Restructuring Legislation provides for a PUCT decision within 150 days after filing. A final order is expected in the fourth quarter of 2005.

TCC Rate Case
In June 2005, the PUCT orally approved a settlement in TCC's rate case, which resulted in a net decrease of $9 million in base rates charged to retail electric providers and wholesale transmission customers. When coupled with reduced depreciation expense due to revised depreciation rates, the removal of a merger-related rate rider credit and other items that were approved in the settlement, TCC estimates that pretax income may improve by approximately $11 million per year.

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 uncertainty, 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 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.

During the second quarter of 2005 as compared to the same period in 2004, higher coal costs reduced gross margins by approximately $44 million and our year-to-date reduction in gross margins related to fuel costs is approximately $100 million. Several major events have impacted fuel costs in 2005. In January, deliveries of coal were restricted due to flooding events and restricted shipping on the Ohio River at Belleville. Central Appalachian coal deliveries were also affected by rail transportation limitations resulting in performance issues among coal suppliers, the railroad, and AEP. 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. That claimed event 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, delivered coal costs are being impacted. The fuel cost escalation that began in the second quarter of 2004 resulted in a larger year-over-year variance for the first half of 2005 than is expected in the second half of 2005.

Energy Policy Act of 2005
The United States House of Representatives and the United States Senate recently agreed to and passed legislation referred to as the Energy Policy Act of 2005. The President has not yet signed the Energy Policy Act of 2005 into law, but public statements from representatives of the White House indicate that he is likely to do so. The Energy Policy Act of 2005 repeals PUHCA, effective six months after the date of enactment. We believe adoption of the Energy Policy Act of 2005 may end 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 would provide 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 Notes

to 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 U.K., LIG and Jefferson Island Storage & Hub, and the sale in January 2005 of a 98% interest in the HPL assets. Consequently, the significance of our three Investments segments is declining.

Our principal operating business segments and their major activities are:

- **Utility Operations:**
  - Domestic generation of electricity for sale to retail and wholesale customers.
  - Domestic electricity transmission and distribution.

- **Investments-Gas Operations:**
  - Gas pipeline and storage services.
  - Gas marketing and risk management activities.

  LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued operations during 2003 and were sold during 2004. We sold a 98% controlling interest in HPL during the first quarter of 2005.

- **Investments-UK Operations:**
  - Generation of electricity in the U.K. for sale to wholesale customers.
  - Coal procurement and transportation to our plants.

  UK Operations were classified as discontinued operations during 2003 and were sold during the third quarter of 2004.

- **Investments-Other:**
  - Bulk commodity barging operations, wind farms, independent power producers and other energy supply related businesses.

  Four independent power producers were sold during the third and fourth quarters of 2004.

AEP Consolidated Results

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2005		2004		2005		2004	
	Earnings	EPS	Earnings	EPS	Earnings	EPS	Earnings	EPS
Utility Operations	$ 247	$ 0.64	$ 184	$ 0.46	$ 600	$ 1.54	$ 488	$ 1.23
Investments - Gas Operations	(2)	(0.01)	(4)	(0.01)	8	0.02	(14)	(0.03)
Investments - Other	(1)	-	(4)	(0.01)	4	0.01	-	-

All Other (a)	(26)	(0.06)	(25)	(0.06)	(40)	(0.10)	(34)	(0.09)
Income Before Discontinued Operations	218	0.57	151	0.38	572	1.47	440	1.11
Investments - Gas Operations	-	-	2	-	-	-	1	-
Investments - UK Operations	-	-	(52)	(0.13)	(5)	(0.01)	(64)	(0.16)
Investments - Other	3	0.01	(1)	-	9	0.02	5	0.01
Discontinued Operations, Net of Tax	3	0.01	(51)	(0.13)	4	0.01	(58)	(0.15)
Net Income	$ 221	$ 0.58	$ 100	$ 0.25	$ 576	$ 1.48	$ 382	$ 0.96
Weighted Average Shares Outstanding		384		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.

Second Quarter of 2005 Compared to Second Quarter of 2004

Income Before Discontinued Operations increased $67 million to $218 million in the second quarter of 2005 compared to the second quarter of 2004.

For the second quarter of 2005, our Utility Operations earnings increased $63 million from second quarter of the previous year primarily due to load and customer growth in all sectors, an increase in off-system sales margins and Ohio and Texas carrying cost accruals. These favorable changes are partially offset by higher fuel costs.

Average shares outstanding decreased to 384 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program approved by our Board of Directors in February 2005.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Income Before Discontinued Operations increased $132 million to $572 million for the six months ended June 30, 2005.

For the six months ended June 30, 2005, our Utility Operations earnings increased $112 million from the same six month period of the previous year driven primarily by the Centrica earnings sharing payments received in March 2005, Ohio and Texas carrying cost accruals and lower maintenance and other operation expenses. These favorable changes are partially offset by higher fuel costs.

Earnings from our Gas Operations increased $22 million from the same six month period of the previous year reflecting favorable results for one month of HPL's operations in 2005 compared with a loss for the six 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.

The loss from our All Other grouping, primarily representing parent company income and expenses, increased $6 million in 2005. This increase is primarily due to lower interest income and lower guarantee fees received in the current period.

Average shares outstanding decreased to 389 million in 2005 from 396 million in 2004 primarily due to the common stock share repurchase program approved by our Board of Directors in February 2005.

Our results of operations by operating segment are discussed below.

Utility Operations

Our Utility Operations include 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 June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in millions)			
Revenues	$ 2,668	$ 2,545	$ 5,282	$ 5,147
Fuel and Purchased Power	956	820	1,861	1,599
Gross Margin	1,712	1,725	3,421	3,548
Depreciation and Amortization	317	308	635	618
Other Operating Expenses	943	994	1,814	1,882
Operating Income	452	423	972	1,048
Other Income (Expense), Net	56	16	204	26
Interest Expense and Preferred Stock Dividend Requirements	156	161	300	327
Income Taxes	105	94	276	259
Income Before Discontinued Operations	$ 247	$ 184	$ 600	$ 488

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

	Three Months Ended		Six Months Ended	
	2005	2004	2005	2004
Energy Summary	(in millions of KWH)			
Retail:				
Residential	9,956	9,740	23,180	23,167
Commercial	9,573	9,390	18,305	18,169
Industrial	13,480	12,902	26,253	25,175
Miscellaneous	639	806	1,284	1,549
Total Retail	33,648	32,838	69,022	68,060
Texas Retail and Other	161	298	389	522
Total	33,809	33,136	69,411	68,582
Wholesale	12,138	13,644	24,773	27,495
Texas Wires Delivery	6,736	6,250	12,254	11,740

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 June 30, 2005, and 2004 were as follows:

	Three Months Ended		Six Months Ended	
	2005	2004	2005	2004
Weather Summary		**(in degree days)**		
Eastern Region				
Actual - Heating	165	168	1,939	2,032
Normal - Heating (a)	176	180	1,988	1,986
Actual - Cooling	287	313	287	316
Normal - Cooling (a)	278	278	281	281
Western Region (b)				
Actual - Heating	26	30	795	913
Normal - Heating (a)	33	33	1,006	1,012
Actual - Cooling	681	659	701	689
Normal - Cooling (a)	645	642	662	660

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

Second Quarter of 2005 Compared to Second Quarter of 2004

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

Second Quarter of 2004		$ 184
Changes in Gross Margin:		
Retail Margins	5	
Texas Supply	(36)	
Transmission Revenues	(21)	
Off-system Sales	38	
Other Revenues	1	
		(13)
Changes in Operating Expenses And Other:		
Maintenance and Other Operation	46	
Depreciation and Amortization	(9)	
Taxes Other Than Income Taxes	5	
Other Income (Expense), Net	40	
Interest Expenses	5	
		87
Income Taxes		(11)
Second Quarter of 2005		$ 247

Income from Utility Operations increased $63 million to $247 million in 2005. The key drivers of the increase were a $46 million decrease in Maintenance and Other Operation expenses and a $40 million increase in Other Income (Expense), Net, partially offset by a $13 million decrease in gross margin.

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

- Retail margins in our utility business were $5 million higher than last year. The primary driver of this increase was a 3% increase in volume attributable to load growth in residential and commercial classes as well as favorable weather in 2005. The margin increase related to load growth was partially offset by higher fuel costs of approximately $44 million, which primarily relates to our utilities in the East with inactive fuel clauses.
- Our Texas Supply business had a $36 million decrease in gross margin as a result of the sale of a majority of our Texas generation assets in the third quarter of 2004 and STP in May 2005.
- Transmission Revenues decreased $21 million primarily due to the loss of through and out rates as mandated by the FERC. Higher transmission revenues in the ECAR region because of the addition of SECA rates partially offset the change in FERC tariffs.
- Margins from Off-system Sales for 2005 were $38 million higher than 2004 primarily due to higher volumes and favorable price margins.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses decreased $46 million. Approximately $11 million of the decrease is due to timing of maintenance projects and different spending patterns experienced in the second quarter of 2005 as compared to the same period in 2004. Additionally, in 2004 we incurred $20 million related to major storms. Also, an $18 million reduction relates to the sale of the Texas generation and STP assets and a $19 million reduction relates to lower labor, incentives, fringes and outside service costs. These favorable variances were partially offset by a $22 million severance accrual in 2005 as a result of our company-wide staffing and budget review, which will ultimately reduce our staffing levels by 466 positions.
- Other Income (Expense), Net increased $40 million primarily due to the following:
  - $20 million related to the recognition of carrying costs by TCC on its net stranded generation costs and its capacity auction true-up asset.
  - $11 million related to the recognition of carrying costs on environmental and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
  - $9 million related to increased AFUDC due to extensive construction activities occurring in 2005.

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

<u>Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004</u>

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

Six Months Ended June 30, 2004		$ 488
Changes in Gross Margin:		
Retail Margins	(61)	
Texas Supply	(56)	
Transmission Revenues	(51)	
Off-system Sales	34	
Other Revenues	7	
		(127)

Changes in Operating Expenses And Other:		
Maintenance and Other Operation	67	
Depreciation and Amortization	(17)	
Taxes Other Than Income Taxes	1	
Other Income (Expense), Net	178	
Interest Expenses	27	
		256
Income Taxes		(17)
Six Months Ended June 30, 2005		$ 600

Income from Utility Operations increased $112 million to $600 million in 2005. The key drivers of the increase were a $178 million increase in Other Income (Expense), Net and a $67 million decrease in Maintenance and Other Operation, partially offset by a $127 million decrease in gross margin.

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

- Overall Retail Margins in our utility business were $61 million lower than last year. The primary driver of this decrease was higher delivered fuel costs of approximately $100 million, of which the majority relates to our East companies with inactive fuel clauses. The higher fuel costs were partially offset by continued customer growth and usage in our residential and commercial classes.
- Our Texas Supply business had a $56 million decrease in gross margin due to the sale of a majority of our Texas generation assets in the third quarter of 2004 and STP in May 2005.
- Transmission Revenues decreased $51 million primarily due to the loss of through and out rates as mandated by the FERC. Higher transmission revenues in the ECAR region because of the addition of SECA rates partially offset the change in FERC tariffs.
- Margins from Off-system Sales for 2005 were $34 million higher than 2004 primarily due to a 3% growth in volume and favorable price margins partially offset by a $41 million decrease in optimization activity.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses decreased $67 million. Approximately $10 million of the decrease is due to timing of maintenance projects and different spending patterns experienced in the first six months of 2005 as compared to the same period in 2004. Expenses were lower by $60 million primarily due to the cancellation of our COLI policies in 2005 and lower labor, incentives and outside service costs in 2005. Also, a $19 million reduction relates to the sale in 2004 of our Texas generation assets. These favorable variances were partially offset by a $22 million severance accrual in 2005 as a result of our company-wide staffing and budget review, which will ultimately reduce our staffing levels by 466 positions.
- Other Income (Expense), Net increased $178 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.
    - $37 million related to the recognition of carrying costs on environmental and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
    - $15 million related to increased AFUDC due to extensive construction activities occurring in 2005.
    - $15 million related to the recognition of carrying costs by TCC on its net stranded generation costs and its capacity auction true-up asset.
- Interest Expenses decreased $27 million due to the refinancing of higher coupon debt and the retirement of debt in 2004 and in the first six months of 2005.

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

Investments-Gas Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Our $2 million net loss from Gas Operations before discontinued operations compares with a $4 million loss recorded in the second quarter of 2004. Due to the sale of a 98% controlling interest in HPL in January 2005, current year results include results from gas trading operations that will wind down over the next several years compared to three months of HPL’s operations in the prior year.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Our $8 million net income from Gas Operations before discontinued operations compares with a $14 million loss recorded in the six months ended June 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 six months of HPL’s operations in the prior year. The variance consists of a $51 million decrease in operation, maintenance and depreciation expenses and a $21 million decrease in interest charges offset by a $42 million decrease in gross margins and an $8 million increase in income taxes.

Investments - UK Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Losses included in discontinued operations from our Investments - UK Operations segment were zero in 2005 as compared to $52 million in 2004 due to the sale of substantially all operations and assets within our Investments - UK Operations segment in July 2004.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Losses included in discontinued operations from our Investments - UK Operations segment were $5 million in 2005 as compared to $64 million in 2004 due 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.

Investments - Other

Second Quarter of 2005 Compared to Second Quarter of 2004

Losses before discontinued operations from our Investments - Other segment decreased by $3 million in 2005 primarily due to the following:

- A $5 million decreased loss due to reductions in outstanding debt at AEP Communications that occurred in October 2004.
- A $3 million increased profit at MEMCO due to favorable operating conditions and strong freight rates in 2005.
- A $3 million increased loss at AEP Resources related to $1 million of increased losses from the Dow plant in 2005 and increased legal and tax expenses of $2 million in 2005.
- The remaining $2 million increased loss relates to several items at various subsidiaries, none of which is individually significant.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Income before discontinued operations from our Investments - Other segment increased by $4 million in 2005 primarily due to the following:

- A $5 million increase at CSW Energy Services related to a current year gain due to a working capital true-up for our November 2004 Numanco sale and a release of product liability and litigation reserves related to our Total Electric Vehicle investment due to the resolution of all open litigation as of March 31, 2005.
- An $8 million increase due to reductions in outstanding debt at AEP Communications that occurred in October 2004.
- A $5 million increase at AEP Coal mostly related to Black Lung Trust settlements.
- A $3 million increase at AEP Investments due to the investment write-down of PHPK Technologies, Inc. in 2004 of $1 million, favorable earnings from Pac Hydro of $1 million in 2005 and $1 million in reduced operations and maintenance at AEP EmTech.
- A $1 million increase at CSW International related to tax reserve adjustments in June 2005.
- A $2 million increase related to several items at various subsidiaries, none of which is individually significant.
- A $17 million decrease at AEP Resources primarily related to a $2 million favorable judgment on an Australian tax issue received in 2004, a $4 million favorable entry in 2004 related to capitalized fuel during construction of the Dow Plant, $5 million of increased losses related to the Dow plant in 2005 and an unfavorable tax adjustment of $4 million booked in 2005.
- A $3 million decrease at our IPPs resulting from an unfavorable tax adjustment in June 2005.

All Other

Second Quarter of 2005 Compared to Second Quarter of 2004

Our parent company's loss for the second quarter of 2005 increased $1 million in comparison to the second quarter of 2004 due to lower interest income in 2005.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Our parent company's loss for the six months ended June 30, 2005 increased $6 million in comparison to the six months ended June 30, 2004 due to lower interest income of $7 million and lower guarantee fees received from affiliates of $2 million, partially offset by lower interest expense of $2 million due to lower short term debt borrowings in 2005 and savings from the redemption of $550 million senior unsecured notes in the second quarter of 2005.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were 31.8% and 33.9%, 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 decrease in the effective tax rate is primarily due to changes in permanent differences.

The effective tax rates for the six months ended 2005 and 2004 were 32.3% and 35.1%, 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. The decrease in the effective tax rate is primarily due to changes in permanent differences 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)

	June 30, 2005		December 31, 2004	
Common Shareholders' Equity	$ 8,382	41.1%	$ 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	11,916	58.5	12,287	58.7
Short-term Debt	14	0.1	23	0.1
Total Capitalization	$ 20,373	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 notes.

As a consequence of the capital changes during the first six months of 2005, our ratio of debt to total capital decreased from 59.1% to 58.6% (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.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. We had an available liquidity position, at June 30, 2005, of approximately $3.3 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	607	
Total Liquidity Sources	3,307	
Less: AEP Commercial Paper Outstanding	-(a)	
Letters of Credit Outstanding	50	
Net Available Liquidity at June 30, 2005	$ 3,257	

(a) Amount does not include JMG commercial paper outstanding in the amount of $14 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 June 30, 2005, this percentage was 53.5%. Nonperformance of these covenants could result in an event of default under these credit agreements. At June 30, 2005, we complied with 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 revolving credit facilities generally prohibit new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under these facilities 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 if our ratings are BBB (or better) from S&P, and Baa2 (or better) from Moody's at any time during the facility's term.

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 June 30, 2005, we were in compliance with this order.

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

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2005 and AEP, Inc. is currently on a "positive" outlook by Moody's.

Our current ratings by the major agencies are as follows:

	Moody's	**S&P**	**Fitch**
Short-term Debt	P-3	A-2	F-2
Senior Unsecured Debt	Baa3	BBB	BBB

If AEP or any of its 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 nationally recognized 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.

	Six Months Ended June 30,	
	2005	**2004**
	(in millions)	

Cash and Cash Equivalents at Beginning of Period	$ 320	$ 778
Cash Flows From (Used For):		
Operating Activities	894	1,275
Investing Activities	484	(565)
Financing Activities	(1,091)	(825)
Net Increase (Decrease) in Cash and Cash Equivalents	287	(115)
Cash and Cash Equivalents at End of Period	$ 607	$ 663
Other Temporary Cash Investments	$ 275	$ 403

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 June 30, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. At June 30, 2005, we had no outstanding short-term borrowings supported by the revolving credit facilities. JMG had commercial paper outstanding in the amount of $14 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 six months ended June 30, 2005 was $25 million. The weighted-average interest rate for our commercial paper during the first six 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 factor in managing and maintaining our liquidity.

Operating Activities

	Six Months Ended June 30,	
	2005	**2004**
	(in millions)	
Net Income	$ 576	$ 382
Plus: (Income) Loss From Discontinued Operations	(4)	58
Income from Continuing Operations	572	440
Noncash Items Included in Earnings	594	797
Changes in Assets and Liabilities	(272)	38
Net Cash Flows From Operating Activities	$ 894	$ 1,275

The key drivers of the decrease in cash from operations for the first six months of 2005 are the Pension Contributions of $204 million and the Gain on Sales of Assets of $115 million, $112 million of which relates to the sale of our Texas REPs to Centrica.

<u>2005 Operating Cash Flow</u>

Our Net Cash Flows From Operating Activities were $894 million for the first six months of 2005. We produced Income from Continuing Operations of $572 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. In addition, there is a current period favorable impact for a net $43 million balance sheet change for risk management contracts that are 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. We made contributions of $204 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 $155 million cash increase from accounts receivable and an increase in the balance of Taxes Accrued of $172 million. Cash increased related to net accounts receivable due to a higher factored balance at June 30, 2005. Taxes Accrued increased because our consolidated tax group was not required to make an estimated federal income tax payment during the first quarter of 2005 and paid $43 million, net of refunds received, during the first half of 2005.

2004 Operating Cash Flow

Our Net Cash Flows From Operating Activities were $1.3 billion for the first six months of 2004. We produced Income from Continuing Operations of $440 million during the period. Income from Continuing Operations for the period included noncash items of $749 million for depreciation, amortization, accretion, deferred taxes and deferred investment tax credits. There was a current period favorable impact for a net $50 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 changes in other activity in the asset and liability accounts are an increase in Taxes Accrued of $140 million and $144 million increase in Fuel, Material and Supplies.

Investing Activities

	Six Months Ended June 30,	
	2005	**2004**
	(in millions)	
Construction Expenditures	$ (1,018)	$ (690)
Change in Other Temporary Cash Investments, Net	(103)	(1)
Purchases of Auction Rate Securities	(1,338)	(201)
Proceeds from the Sale of Auction Rate Securities	1,441	203
Proceeds from Sale of Assets	1,500	131
Other	2	(7)
Net Cash Flows From (Used For) Investing Activities	$ 484	$ (565)

Our Net Cash Flows From Investing Activities were $484 million in 2005 primarily due to proceeds from the sale of HPL and STP in 2005. We used the cash from asset sales to repurchase common stock. Our Construction Expenditures include environmental, transmission and distribution investments as we had planned. Our remaining Construction Expenditures for 2005 are estimated to be approximately $1.7 billion.

We purchase auction rate securities with cash available for short-term investment. During the first half of 2005, we purchased $1.3 billion of securities and received $1.4 billion of proceeds from sale, which included the sale of our auction rate securities held at December 31, 2004, as reflected above in the Change In Other Temporary Cash Investments, Net line.

Our Net Cash Flows Used For Investing Activities were $565 million in 2004 primarily due to Construction Expenditures partially offset by the 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.

Financing Activities

	Six Months Ended June 30, 2005	2004
	(in millions)	
Issuance of Common Stock	$ 28	$ 11
Repurchase of Common Stock	(427)	-
Issuance/Retirement of Debt, net	(353)	(555)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid on Common Stock	(273)	(277)
Net Cash Flows Used For Financing Activities	$ (1,091)	$ (825)

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

Our Net Cash Flows Used For Financing Activities were $825 million in 2004. During 2004, we retired debt using cash from operating activities. We retired approximately $986 million of long-term debt, excluding $25 million related to an asset sale. We increased our short-term debt by $188 million and issued approximately $243 million of long-term debt.

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. 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, all future carrying costs through September 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 is scheduled to begin on September 26, 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 half of 2005, TCC began to accrue carrying costs based on this order. Through June 30, 2005, TCC has computed carrying costs of $483 million, of which TCC has recognized $317 million to-date. The equity component of the carrying costs, which totals $166 million through June 30, 2005, will be recognized in income as collected.

In an April 2005 PUCT open meeting regarding another nonaffiliated utility's True-up Proceeding, the other utility was required to use a lower rate to compute its carrying costs than its filed unbundled cost of service rate. TCC's facts differ from the other utility's; however, if the PUCT ultimately determines that a similar lower rate 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 would have an adverse impact on future results of operations and cash flows. Through June 30, 2005, such reversal would approximate $60 million, of which $9 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 the 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 $2.4 billion request for recovery of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation and that our $1.7 billion recorded net true-up regulatory asset, inclusive of carrying costs at June 30, 2005, is probable of recovery at this time. However, we anticipate that other parties will contend in our proceeding that 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 an adverse effect on future results of operations, cash flows and possibly financial condition.

TCC Rate Case

TCC has an on-going T&D rate review before the PUCT. In that rate review, the PUCT has decided all issues except the amount of affiliate expenses to include in revenue requirements. Through an oral ruling, the PUCT approved the nonunanimous settlement filed in June 2005 that provides for an $11 million disallowance of affiliate expenses which, when combined with the previous decisions, results in a total reduction in TCC's annual base rates of $9 million. A draft final order has been issued reflecting the $9 million reduction in TCC's annual base rates. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. It is anticipated that the PUCT will approve the final written order at its August 2005 open meeting. If the final written order differs from the draft order, it could impact projected annual pretax earnings effect.

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 additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues. 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 were increased by $14 million for CSPCo and $40 million for OPCo in the first half of 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo relate to 2004 environmental carrying costs and RTO costs.

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. If the RSP order was determined to be illegal under the Restructuring Legislation, as contended by the two intervenors, it would have an adverse effect on results of operations, cash flow 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 $18 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover approximately $237 million in 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 Rate Stabilization Plans. In Phase 3, which begins when the plant enters commercial operation, the Ohio companies would recover the projected $1.2 billion cost of the plant and a return on the unrecovered cost over its operating life along with fuel, replacement power and operation and maintenance costs.

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, allowing for the implementation of new base rates in June 2005.

PSO Fuel and Purchased Power

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 the alleged improperly allocated off-system sales margins between AEP East and AEP West companies. Their overall recommendations related to the allocation 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.

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 which 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. Approximately $14 million of the amount requested represents incremental E&R costs for the twelve months ended June 30, 2005 and $48 million represents projected incremental E&R costs to be incurred for the twelve months ending June 30, 2006. The $62 million request relates to 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, recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kilovolt transmission line construction and other incremental T&D system reliability costs.

APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. If approved, the recovery factor will be applied as a 9.18% surcharge to customer bills. APCo proposed the difference between the actual incremental costs incurred and the cost recovered be subject to future rate adjustment.

On July 14, 2005, the Virginia SCC issued an order that established a procedural schedule in APCo's proceeding including a public hearing on February 7, 2006. The order provided that no portion of APCo's application should become effective pending further decision of the Virginia SCC. Each party to the proceeding may file legal arguments on or before September 6, 2005, on whether and, under what circumstances, the Virginia SCC has the authority to make effective, on an interim basis subject to refund, any portion of APCo's requested rate change. We are unable to predict the final outcome of this proceeding. If the Virginia SCC denies recovery of net incremental amounts deferred, it would adversely affect future results of operations and cash flows.

APCo and WPCo West Virginia Rate Case

On July 1, 2005, APCo and WPCo formally notified the Public Service Commission of West Virginia of their intent to file a joint general rate case seeking increases in retail rates in the third quarter of 2005. The filing will include, among other things, a request to reinstate the suspended expanded fuel, net energy and purchased power clause and to provide for scheduled rate recovery of significant environmental and transmission expenditures. As of June 30, 2005 and December 31, 2004, we had $52 million of previously over-recovered fuel, net energy and purchased power costs related to APCo recorded in regulatory liabilities. Management is unable to predict the ultimate effect of this filing on 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 SECA revenues of $32 million and $57 million for the second quarter and first half of 2005, respectively. In addition, we recognized $11 million of 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 and municipal, 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 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 proposed 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. This investigation provides AEP an opportunity to propose and support a new PJM rate regime that could mitigate losses from the elimination of T&O transmission rates and the discontinuance of the SECA rate collections.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, 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 or within the PJM and MidWest ISO Regions that compensates for AEP's T&O revenue losses, 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 six 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) Bank of Montreal Claim, (6) Natural Gas Markets Lawsuits, (7) Conserstone Lawsuit and (8) TEM Litigation. Additionally, refer to the Commitments and Contingencies footnote in our Condensed Notes to Condensed Consolidated Financial Statements for further discussion of these matters.

Federal EPA Complaint and Notice of Violation

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 has filed a petition for review of this Initial Decision, which the SEC has granted. The SEC is reviewing the Initial Decision. We believe adoption of the Energy Policy Act of 2005 may end litigation challenging our merger with CSW.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four of our subsidiaries, certain nonaffiliated energy companies and ERCOT. 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. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, sought leave to intervene as plaintiffs asserting similar claims. In June 2004, the Court dismissed all claims against the AEP companies. TCE has 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. 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. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

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 SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey

Plant relate to testing and reporting of volatile organic compound emissions. 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. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. 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 $228,312 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.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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

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) carbon dioxide public nuisance claims, (6) costs for spent nuclear fuel disposal and decommissioning, and (7) 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 is slightly revised from the proposed version released in January 2004, and 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 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.

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 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, both the CAIR and CAMR 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, or if states elect to impose additional requirements on individual units that are already subject to CAIR and/or the 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 Litigation

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

The 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 is underway and closing arguments will be heard on September 22, 2005.

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 are 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 in January 2005 and to the Federal EPA's complaint in July 2005, denying the allegations and stating its defense.

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 test, utilizing a five-year look back period to establish actual baseline emissions for utilities and a ten-year period for other sources, and excluding increased emissions unrelated to a physical change from the projected emissions, including 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.

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 will pay an immaterial civil penalty and 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 selective catalytic reduction system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

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, Credit Risk Management, Market Risk Oversight, and 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
Six Months Ended June 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)	(52)	(4)	12	(44)
Fair Value of New Contracts When Entered During the Period (b)	2	-	-	2
Net Option Premiums Paid/(Received) (c)	(1)	-	-	(1)
Change in Fair Value Due to Valuation Methodology Changes	-	-	-	-

Changes in Fair Value of Risk Management Contracts (d)	30	(3)	-	27
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(13)	-	-	(13)
Total MTM Risk Management Contract Net Assets (Liabilities) at June 30, 2005	$ 243	$ (7)	$ -	236
Net Cash Flow and Fair Value Hedge Contracts (f)				(37)
Ending Net Risk Management Assets at June 30, 2005				$ 199

(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 June 30, 2005
(in millions)

	Utility Operations	**Investments-Gas Operations**	**Total**
Current Assets	$ 376	$ 222	$ 598
Noncurrent Assets	529	164	693
Total Assets	905	386	1,291
Current Liabilities	(325)	(217)	(542)
Noncurrent Liabilities	(337)	(176)	(513)
Total Liabilities	(662)	(393)	(1,055)
Total Net Assets (Liabilities), excluding Hedges	$ 243	$ (7)	$ 236

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

	MTM Risk Management Contracts (a)	PLUS: Hedges	Total (b)
Current Assets	$ 598	$ 1	$ 599
Noncurrent Assets	693	1	694
Total MTM Derivative Contract Assets	1,291	2	1,293
Current Liabilities	(542)	(36)	(578)
Noncurrent Liabilities	(513)	(3)	(516)
Total MTM Derivative Contract Liabilities	(1,055)	(39)	(1,094)
Total MTM Derivative Contract Net Assets	$ 236	$ (37)	$ 199

(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 June 30, 2005
(in millions)

	Remainder 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Utility Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ (32)	$ 6	$ 23	$ -	$ -	$ -	$ (3)
Prices Provided by Other External Sources - OTC							

Broker Quotes (a)	99	107	52	39	-	-	297
Prices Based on Models and Other Valuation Methods (b)	(40)	(60)	(18)	7	33	27	(51)
Total	$ 27	$ 53	$ 57	$ 46	$ 33	$ 27	$ 243
Investments - Gas Operations:							
Prices Actively Quoted - Exchange Traded Contracts	$ (5)	$ (7)	$ 5	$ -	$ -	$ -	$ (7)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	20	(3)	(3)	-	-	-	14
Prices Based on Models and Other Valuation Methods (b)	(3)	(3)	-	(2)	(4)	(2)	(14)
Total	$ 12	$ (13)	$ 2	$ (2)	$ (4)	$ (2)	$ (7)
Total:							
Prices Actively Quoted - Exchange Traded Contracts	$ (37)	$ (1)	$ 28	$ -	$ -	$ -	$ (10)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	119	104	49	39	-	-	311
Prices Based on Models and Other Valuation Methods (b)	(43)	(63)	(18)	5	29	25	(65)
Total	$ 39	$ 40	$ 59	$ 44	$ 29	$ 25	$ 236

(a) Prices Provided by Other External Sources- OTC Broker Quotes reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party on-line platforms.
(b) Prices Based on Models and Other Valuation Methods is in the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $24 million of this mark-to-market value is in 2010.
(d) Amounts exclude Cash Flow and Fair Value Hedges.

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

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of June 30, 2005

Commodity	**Transaction Class**	**Market/Region**	**Tenor (in months)**
Natural Gas	Futures	NYMEX/Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	36
	Swaps	Gas East - Northeast, Mid-continent, Gulf Coast, Texas	36
	Swaps	Gas West - Rocky Mountains, West Coast	42

	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East - PJM	36
	Physical Forwards	Power East - MISO Cin Hub	42
	Physical Forwards	Power East - PJM West	42
	Physical Forwards	Power East - AEP Dayton (PJM)	18
	Physical Forwards	Power East - NEPOOL	42
	Physical Forwards	Power East - NYPP	42
	Physical Forwards	Power East - ERCOT	42
	Physical Forwards	Power East - Com Ed	18
	Physical Forwards	Power East - Entergy	6
	Physical Forwards	Power West - Palo Verde, Mead	54
	Physical Forwards	Power West - North Path 15, South Path 15	54
	Physical Forwards	Power West - Mid Columbia	54
	Peak Power Volatility (Options)	Cinergy, PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO_2, NO_x	42
Coal	Physical Forwards	PRB, NYMEX, CSX	30

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

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

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

The tables below provide detail on designated, effective cash flow hedges included in our Condensed Consolidated Balance Sheets. The data in the first table indicates the magnitude of cash flow hedges that we have in place. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables. This table further indicates what portions of designated, effective hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2004 to June 30, 2005.

Information on energy commodity risk management activities is presented separately from interest rate risk management activities.

Cash FlowHedges included in Accumulated Other Comprehensive Income (Loss)
On the Condensed Consolidated Balance Sheet as of June 30, 2005
(in millions)

	Accumulated Other	After Tax Portion Expected

	Comprehensive Income (Loss) After Tax (a)	to be Reclassified to Earnings During the Next 12 Months (b)
Power and Gas	$ (19)	$ (18)
Interest Rate	(32)	(5)
Total	$ (51)	$ (23)

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance, December 31, 2004	$ 23	$ (23)	$ -
Changes in Fair Value (c)	(15)	(12)	(27)
Reclassifications from AOCI to Net Income (d)	(27)	3	(24)
Ending Balance, June 30, 2005	$ (19)	$ (32)	$ (51)

(a) "Accumulated Other Comprehensive Income (Loss) After Tax" - Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.

(b) "After Tax Portion Expected to be Reclassified to Earnings During the Next 12 Months" - Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.

(c) "Changes in Fair Value" - Changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(d) "Reclassifications from AOCI to Net Income" - Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into Net Income during the reporting period. Amounts are reported net of related income taxes.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At June 30, 2005, our credit exposure net of collateral to sub investment grade counterparties was approximately 12.4%,expressed in terms of net MTM assets and net receivables. As of June 30, 2005, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
Investment Grade	$ 767	$ 140	$ 627	2	$ 178
Split Rating	13	3	10	1	9
Noninvestment Grade	193	116	77	3	66
No External Ratings:					
Internal Investment Grade	50	-	50	1	34
Internal Noninvestment Grade	25	6	19	2	17
Total	$ 1,048	$ 265	$ 783	9	$ 304

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2007. This table presents a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of June 30, 2005

	Remainder 2005	2006	2007
Estimated Plant Output Hedged	91%	85%	85%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

VaR Model

Six Months Ended June 30, 2005 (in millions)				Twelve Months Ended December 31, 2004 (in millions)			
End	High	Average	Low	End	High	Average	Low
$4	$5	$2	$1	$3	$19	$5	$1

Our VaR model results are adjusted using standard statistical treatments to calculate the CCRO VaR reporting metrics listed below.

CCRO VaR Metrics
(in millions)

	June 30, 2005	Average for Year-to-Date 2005	High for Year-to-Date 2005	Low for Year-to-Date 2005
95% Confidence Level, Ten-Day Holding Period	$ 15	$ 9	$ 17	$ 5
99% Confidence Level, One-Day Holding Period	$ 6	$ 4	$ 7	$ 2

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $540 million at June 30, 2005 and $601 million at December 31, 2004. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas, coal, emissions and to a lesser degree other commodities. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations and our Chief Risk Officer and risk management staff. When risk management activities exceed certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
REVENUES				
Utility Operations	$ 2,649	$ 2,508	$ 5,186	$ 5,089
Gas Operations	19	779	376	1,431
Other	105	124	194	255
TOTAL	2,773	3,411	5,756	6,775
EXPENSES				
Fuel for Electric Generation	772	734	1,543	1,428
Purchased Electricity for Resale	183	87	313	170
Purchased Gas for Resale	1	701	250	1,286
Maintenance and Other Operation	873	978	1,663	1,842
Depreciation and Amortization	325	320	652	639
Taxes Other Than Income Taxes	173	181	361	374
TOTAL	2,327	3,001	4,782	5,739
OPERATING INCOME	446	410	974	1,036
Other Income	106	59	345	121
Other Expense	(40)	(38)	(106)	(74)
Investment Value Losses	-	(2)	-	(2)
INTEREST AND OTHER CHARGES				
Interest Expense	188	199	361	398
Preferred Stock Dividend Requirements of Subsidiaries	3	1	5	3
TOTAL	191	200	366	401
INCOME BEFORE INCOME TAXES	321	229	847	680
Income Taxes	103	78	275	240
INCOME BEFORE DISCONTINUED OPERATIONS	218	151	572	440
DISCONTINUED OPERATIONS, Net of Tax	3	(51)	4	(58)
NET INCOME	$ 221	$ 100	$ 576	$ 382
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING	384	396	389	396

EARNINGS PER SHARE				
Income Before Discontinued Operations	$ 0.57	$ 0.38	$ 1.47	$ 1.11
Discontinued Operations	0.01	(0.13)	0.01	(0.15)
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$ 0.58	$ 0.25	$ 1.48	$ 0.96
CASH DIVIDENDS PAID PER SHARE	$ 0.35	$ 0.35	$ 0.70	$ 0.70

See Condensed Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(in millions)
(Unaudited)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 607	$ 320
Other Temporary Cash Investments	275	275
Accounts Receivable:		
Customers	717	930
Accrued Unbilled Revenues	354	592
Miscellaneous	33	79
Allowance for Uncollectible Accounts	(46)	(77)
Total Accounts Receivable	1,058	1,524
Fuel, Materials and Supplies	729	852
Risk Management Assets	599	737
Margin Deposits	112	113
Other	150	200
TOTAL	3,530	4,021
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,346	15,969
Transmission	6,369	6,293
Distribution	10,471	10,280
Other (including gas, coal mining and nuclear fuel)	3,093	3,585
Construction Work in Progress	1,296	1,159
Total	37,575	37,286
Accumulated Depreciation and Amortization	14,682	14,485
TOTAL - NET	22,893	22,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,707	3,601
Securitized Transition Assets	622	642
Spent Nuclear Fuel and Decommissioning Trusts	1,095	1,053
Investments in Power and Distribution Projects	138	154
Goodwill	76	76
Long-term Risk Management Assets	694	470
Prepaid Pension Obligations	384	386
Other	754	831
TOTAL	7,470	7,213
Assets Held for Sale	46	628

TOTAL ASSETS	$ 33,939	$ 34,663

See Condensed Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 925	$ 1,051
Short-term Debt	14	23
Long-term Debt Due Within One Year (a)	1,064	1,279
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	66
Risk Management Liabilities	578	608
Accrued Taxes	788	611
Accrued Interest	180	180
Customer Deposits	380	414
Other	602	775
TOTAL	4,531	5,007
NONCURRENT LIABILITIES		
Long-term Debt (a)	10,852	11,008
Long-term Risk Management Liabilities	516	329
Deferred Income Taxes	4,663	4,819
Regulatory Liabilities and Deferred Investment Tax Credits	2,618	2,540
Asset Retirement Obligations	860	827
Employee Benefits and Pension Obligations	546	730
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	162	166
Deferred Credits and Other	747	411
TOTAL	20,964	20,830
Liabilities Held for Sale	1	250
TOTAL LIABILITIES	25,496	26,087
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2005	2004
Shares Authorized	600,000,000	600,000,000
Shares Issued	405,896,571	404,858,145

	2005	2004
(21,499,992 and 8,999,992 shares were held in treasury at June 30, 2005 and December 31, 2004, respectively)	2,638	2,632
Paid-in Capital	3,813	4,203
Retained Earnings	2,327	2,024

Accumulated Other Comprehensive Income (Loss)	(396)	(344)
TOTAL	8,382	8,515
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 33,939	$ 34,663

(a) See Accompanying Schedule.

See Condensed Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(in millions)
(Unaudited)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 576	$ 382
Plus: (Income) Loss from Discontinued Operations	(4)	58
Income from Continuing Operations	572	440
Adjustments for Noncash Items:		
Depreciation and Amortization	652	639
Accretion of Asset Retirement Obligations	35	31
Deferred Income Taxes	(75)	92
Deferred Investment Tax Credits	(15)	(13)
Asset Impairments, Investment Value Losses and Other Related Charges	-	2
Carrying Costs	(56)	-
Amortization of Deferred Property Taxes	10	(4)
Mark-to-Market of Risk Management Contracts	43	50
Pension Contributions	(204)	(8)
Over/Under Fuel Recovery	(45)	70
Gain on Sales of Assets	(115)	(3)
Change in Other Noncurrent Assets	(80)	10
Change in Other Noncurrent Liabilities	(121)	(34)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	155	157
Fuel, Materials and Supplies	(29)	(144)
Accounts Payable	84	(158)
Taxes Accrued	172	140
Customer Deposits	(34)	83
Interest Accrued	(5)	(8)
Other Current Assets	63	7
Other Current Liabilities	(113)	(74)
Net Cash Flows From Operating Activities	894	1,275
INVESTING ACTIVITIES		
Construction Expenditures	(1,018)	(690)
Change in Other Temporary Cash Investments, Net	(103)	(1)
Purchases of Auction Rate Securities	(1,338)	(201)
Proceeds from the Sale of Auction Rate Securities	1,441	203
Proceeds from Sale of Assets	1,500	131
Other	2	(7)
Net Cash Flows From (Used For) Investing Activities	484	(565)
FINANCING ACTIVITIES		
Issuance of Common Stock	28	11
Repurchase of Common Stock	(427)	-

Issuance of Long-term Debt	1,660	243
Change in Short-term Debt, Net	27	188
Retirement of Long-term Debt	(2,040)	(986)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid on Common Stock	(273)	(277)
Net Cash Flows Used For Financing Activities	(1,091)	(825)
Net Increase (Decrease) in Cash and Cash Equivalents	287	(115)
Cash and Cash Equivalents at Beginning of Period	320	778
Cash and Cash Equivalents at End of Period	$ 607	$ 663
Net Increase in Cash and Cash Equivalents from Discontinued Operations	$ -	$ 2
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	-	13
Cash and Cash Equivalents from Discontinued Operations - End of Period	$ -	$ 15

See Condensed Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(in millions)
(Unaudited)

	Common Stock				Accumulated Other	
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	404	$ 2,626	$ 4,184	$ 1,490	$ (426)	$ 7,874
Issuance of Common Stock	1	4	7			11
Common Stock Dividends				(277)		(277)
Other			2			2
TOTAL						7,610
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(1)	(1)
Cash Flow Hedges, Net of Tax of $41					75	75
Minimum Pension Liability, Net of Tax of $10					17	17
NET INCOME				382		382
TOTAL COMPREHENSIVE INCOME						473
JUNE 30, 2004	405	$ 2,630	$ 4,193	$ 1,595	$ (335)	$ 8,083
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515
Issuance of Common Stock	1	6	22			28
Common Stock Dividends				(273)		(273)
Repurchase of Common Stock			(427)			(427)
Other			15			15
TOTAL						7,858
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(1)	(1)
Cash Flow Hedges, Net of Tax of $28					(51)	(51)
NET INCOME				576		576
TOTAL COMPREHENSIVE INCOME						524
JUNE 30, 2005	406	$ 2,638	$ 3,813	$ 2,327	$ (396)	$ 8,382

:e Condensed Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
June 30, 2005 and December 31, 2004
(Unaudited)
(in millions)

	2005	2004
First Mortgage Bonds	$ 242	$ 417
Defeased TCC First Mortgage Bonds (a)	84	84
Installment Purchase Contracts	2,055	1,773
Notes Payable	928	939
Senior Unsecured Notes	7,292	7,717
Securitization Bonds	669	698
Notes Payable to Trust	113	113
Equity Unit Senior Notes (b)	345	345
Long-term DOE Obligation (c)	232	229
Other Long-term Debt	3	14
Equity Unit Contract Adjustment Payments	4	9
Unamortized Discount, Net	(51)	(51)
TOTAL LONG-TERM DEBT OUTSTANDING	11,916	12,287
Less Portion Due Within One Year	1,064	1,279
TOTAL LONG-TERM PORTION	$ 10,852	$ 11,008

(a) On May 7, 2004, we deposited cash and treasury securities of $125 million with a trustee to defease all of TCC's outstanding First Mortgage Bonds. Trust fund assets related to this obligation of $70 and $72 million are included in Other Temporary Cash Investments at June 30, 2005 and December 31, 2004, respectively, and $22 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at both June 30, 2005 and December 31, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) In June 2005, we remarketed $345 million of 5.75% Equity Unit Senior Notes originally issued in June 2002 with new notes bearing a 4.709% interest rate. See "Remarketing of Senior Notes" section of Note 11.

(c) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. I&M is the only AEP subsidiary that generated electric power with nuclear fuel prior to that date. Trust fund assets of $264 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at June 30, 2005 and December 31, 2004, respectively.

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2004 Annual Report as incorporated in and filed with our 2004 Form 10-K.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments that are necessary for a fair presentation of our results of operations for interim periods.

Other Income and Other Expense

The following table provides the components of Other Income and Other Expense as presented in our Condensed Consolidated Statements of Income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in millions)		(in millions)	
Other Income:				
Interest and Dividend Income	$ 14	$ 5	$ 25	$ 11
Equity Earnings	2	3	7	10
Nonutility Revenue	29	29	92	58
Gain on Sale of Texas REPs	-	-	112	-
Carrying Charges	36	(1)	56	1
Other	25	23	53	41
Total Other Income	$ 106	$ 59	$ 345	$ 121
Other Expense:				
Nonutility Expense	$ 21	$ 23	$ 78	$ 51
Other	19	15	28	23
Total Other Expense	$ 40	$ 38	$ 106	$ 74

Components of Accumulated Other Comprehensive Income (Loss)

The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	June 30, 2005	December 31, 2004
	(in millions)	
Foreign Currency Translation Adjustments, net of tax	$ 5	$ 6
Securities Available for Sale, net of tax	(1)	(1)
Cash Flow Hedges, net of tax	(51)	-
Minimum Pension Liability, net of tax	(349)	(349)

Total	$ (396)	$ (344)

At June 30, 2005, we expect to reclassify approximately $23 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations. Eighteen months is the maximum length of time that we are hedging our exposure to variability in future cash flows with contracts designated as cash flow hedges.

Accounting for Asset Retirement Obligations (ARO)

The following is a reconciliation of the beginning and ending aggregate carrying amounts of ARO:

	Nuclear Decommissioning	Ash Ponds	Wind Mills and Mining Operations	Total
		(in millions)		
ARO at January 1, 2005, Including STP	$ 960	$ 84	$ 32	$ 1,076
Accretion Expense	31	3	1	35
Liabilities Incurred	-	-	8	8
ARO at June 30, 2005, Including STP	991	87	41	1,119
Less ARO Liability for STP (a)	(256)	-	-	(256)
ARO at June 30, 2005	$ 735	$ 87	$ 41	$ 863(b)

(a) The ARO for TCC's share of STP was included in Liabilities Held for Sale at December 31, 2004 and was subsequently transferred to the buyer with the sale in the second quarter of 2005 (see "Texas Plants-South Texas Project" section of Note 7).

(b) The current portion of our ARO, totaling $3 million, is included in Other in the Current Liabilities section in our Condensed Consolidated Balance Sheets.

Accretion expense is included in Maintenance and Other Operation expense in our accompanying Condensed Consolidated Statements of Income.

At June 30, 2005 and December 31, 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $832 million and $791 million, respectively, relating to Cook Plant recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Condensed Consolidated Balance Sheets.

Supplementary Information

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Related Party Transactions		(in millions)		
AEP Consolidated Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$ 48	$ 36	$ 91	$ 70

	Six Months Ended June 30, 2005	2004
Cash Flow Information	(in millions)	
Cash was paid (received) for:		

Interest (net of capitalized amounts)	$ 322	$ 378
Income Taxes	86	(43)
Change in construction-related Accounts Payable included in Investing Activities - Construction Expenditures	9	(22)
Noncash Investing and Financing Activities:		
Acquisitions Under Capital Leases	22	27
(Disposition) of Liabilities Related to Divestitures	(22)	(11)

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income.

In connection with preparation of the first quarter of 2005 financial statements, we concluded that it was appropriate to classify our auction rate securities as other temporary cash investments. Previously, such investments had been classified as cash and cash equivalents. Accordingly, we have revised the classification to exclude from cash and cash equivalents $103 million at December 31, 2004, and to include such amounts as other temporary cash investments. There were no auction rate securities held at June 30, 2005. At December 31, 2003, auction rate securities approximated $200 million. These revisions had no impact on our previously reported results of operations, operating cash flows or working capital.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2005 that we have determined relate to our operations.

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

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25 "Accounting for Stock Issued to Employees." The statement is effective as of the first annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially adopting the statement.

We will implement SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. We will apply the principles of SAB 107 in conjunction with our adoption of SFAS 123R.

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

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and FASB Statement No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that does not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005 with early implementation permitted for accounting changes and corrections of errors made in fiscal years beginning after the date this statement is issued. SFAS 154 is effective for us beginning January 1, 2006 and will be applied when applicable.

FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143 "Accounting for Asset Retirement Obligations." FIN 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

We will implement FIN 47 during the fourth quarter for the fiscal year ending December 31, 2005. Implementation will require a potential adjustment for the cumulative effect for any nonregulated operations of initially adopting FIN 47 to be recorded as a change in accounting principle, disclosure of pro forma liabilities and asset retirement obligations, and other additional disclosures. We have not completed our evaluation of any potential impact to our results of operations or financial condition.

EITF Issue 03-13 "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations"

This issue developed a model for evaluating which cash flows are to be considered in determining whether cash flows have been or will be eliminated and what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. During the first quarter of 2005, we applied this issue to components that were disposed of or classified as held for sale, including the HPL disposition (see "Houston Pipe Line Company" section of Note 7).

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, business combinations, liabilities and equity, revenue recognition, pension plans, fair value measurements and related tax impacts. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in our 2004 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and at state commissions. The Rate Matters note within our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending. The following sections discuss current activities and update the 2004 Annual Report.

APCo Virginia Environmental and Reliability Costs

In April 2004, the Virginia Electric Restructuring Act was amended to include a provision which permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred 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. Approximately $14 million of the amount requested represents incremental E&R costs for the twelve months ended June 30, 2005 and $48 million represents projected incremental E&R costs to be incurred for the twelve months ending June 30, 2006. The $62 million request relates to 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, recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kilovolt transmission line construction and other incremental T&D system reliability costs.

Through June 30, 2005, APCo has deferred for future recovery $9 million consisting of the $14 million of incremental E&R costs incurred to date, partially offset by $2 million of equity carrying costs not recognizable until collected and $3 million of capitalized interest recorded on the incremental E&R capital investments. APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. If approved, the recovery factor will be applied as a 9.18% surcharge to customer bills. APCo proposed to practice under/over-recovery accounting for the difference between the actual incremental costs incurred and the cost recovered.

On July 14, 2005, the Virginia SCC issued an order that established a procedural schedule in APCo's proceeding including a public hearing on February 7, 2006. The order provided that no portion of APCo's application should become effective pending further decision of the Virginia SCC. Each party to the proceeding may file legal arguments on or before September 6, 2005, on whether and, under what circumstances, the Virginia SCC has the authority to make effective, on an interim basis subject to refund, any portion of APCo's requested rate change. We are unable to predict the final outcome of this proceeding. If the Virginia SCC denies recovery of net incremental amounts deferred of $9 million, it would adversely affect future results of operations and cash flows.

APCo and WPCo West Virginia Rate Case

On July 1, 2005, APCo and WPCo formally notified the Public Service Commission of West Virginia of their intent to file a joint general rate case seeking increases in retail rates in the third quarter of 2005. The filing will include, among other things, a request to reinstate the suspended expanded fuel, net energy and purchased power clause and to provide for scheduled rate recovery of significant environmental and transmission expenditures. As of June 30, 2005 and December 31, 2004, we had $52 million of previously over-recovered fuel, net energy and purchased power costs related to APCo recorded in regulatory liabilities on our Condensed Consolidated Balance Sheets. Management is unable to predict the ultimate effect of this filing on revenues, results of operations, cash flows and financial condition.

I&M Indiana Settlement Agreement

In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005 and filed the agreement with the IURC on March 14, 2005. The IURC approved the agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor will be adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), the ratio of the sum of fuel and one half maintenance expenses incurred by the pool members to the total kilowatt-hours of net generation, excluding I&M, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total actual fuel costs (except during a Cook Plant outage of greater than 60 days) are under the cap prices, the excess will be credited to customers over the next two fuel adjustment clause filings. Under the settlement, fuel costs in excess of the cap price cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M’s control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

Our cumulative under recovery for March 2004 through June 2005 recorded as fuel expense is $7 million. If future fuel cost per KWH through June 30, 2007 continue to exceed the caps, or if the base rate cap precludes I&M from seeking timely rate increases to recover increases in its cost of service through June 30, 2007, future results of operations and cash flows would be adversely affected.

I&M Michigan Fuel Recovery Plan

In September 2004, I&M filed its 2005 Power Supply Cost Recovery (PSCR) Plan, with the requested PSCR factors implemented pursuant to the statute effective with January 2005 billings, replacing the 2004 factors. On March 29, 2005, the Michigan Public Service Commission (MPSC) issued an order approving an agreement authorizing I&M’s proposed 2005 PSCR Plan factors.

On March 31, 2005, I&M filed its 2004 PSCR Reconciliation seeking recovery of approximately $2 million of unrecovered PSCR fuel costs and interest proposed to be recovered through the application of customer bill surcharges during October 2005 through December 2005.

On April 28, 2005, the MPSC issued an Opinion and Order approving I&M’s proposed 2004 PSCR factors as billed and finding in favor of I&M on all issues, including the proposed treatment of net SO_2 and NO_x credits.

PSO Fuel and Purchased Power

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. In September 2003, the OCC expanded the case to include a full prudence review of PSO’s 2001 fuel and purchased power practices. The OCC has indicated that PSO will not be allowed recovery of the $42 million until the margin issue discussed below is decided. If the OCC denies recovery of any portion of the $42 million under-recovery of fuel costs, future results of operations and cash flows would be adversely affected.

In the review of PSO’s 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and that the AEP West companies should have been allocated greater margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. On July 25, 2005, the OCC Staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East and AEP West companies. Their overall recommendations related to the allocation would result in an increase in off-system sales margins and thus, a reduction to 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 PSO will defend vigorously its position. Accordingly, PSO has not recorded a provision for the off-system sales margins issue. If the OCC reduces recovery of any portion of the fuel costs as a result of the off-system sales margins issue, future results of operations and cash flows would be adversely affected.

In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power practices for 2003. On June 10, 2005, the OCC decided to have its staff conduct that review. Management is unable to predict the ultimate effect of these proceedings on revenues, results of operations, cash flows and financial condition.

PSO Lawton Power Supply Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration Incorporated seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs. The order did not approve recovery by PSO of the resultant purchased power costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court. In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Oklahoma Supreme Court issued a decision on June 21, 2005 affirming portions of the OCC's order and remanding certain provisions. The Court affirmed the OCC's finding that Lawton established a legally enforceable obligation and ruled that it was within the OCC's discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO's avoided energy cost. The decision also authorizes the OCC to revisit its determination of PSO's avoided capacity costs. We are unable to predict the final outcome of the remand, however, if the OCC were to deny recovery of the full cost of the Agreement, it would adversely affect future results of operations and cash flows.

Upon resolution of the litigation, management will review any resultant transaction to determine if it can be accounted for as a purchased power transaction or whether it will be accounted for as a lease or as a generating plant asset on the balance sheet under FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities."

PSO Rate Review

PSO has been involved in a commission staff-initiated base rate review before the OCC which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. 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, allowing for the implementation of new base rates in June 2005.

TCC Rate Case

TCC has an on-going T&D rate review before the PUCT. In that rate review, the PUCT has decided all issues except the amount of affiliate expenses to include in revenue requirements. Through an oral ruling, the PUCT approved the nonunanimous settlement filed in June 2005 that provides for an $11 million disallowance of affiliate expenses which, when combined with the previous decisions, results in a total reduction in TCC's annual base rates of $9 million. A draft final order has been issued reflecting the $9 million reduction in TCC's annual base rates. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. It is anticipated that the PUCT will approve the final written order at its August 2005 open meeting. If the final written order differs from the draft order, it could impact projected annual pretax earnings effect.

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

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, Texas Court of Appeals issued a decision reversing the District Court on the loss of load issue but otherwise affirming its decision. The amount of unaccounted for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million. We are reviewing the decision and are considering various options. Our third quarter pretax earnings may be adversely affected by $3 million as a result of this decision.

Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new T&D rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The District Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable T&D rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale of our former affiliated REPs is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

Hold Harmless Proceeding

In a July 2002 order conditionally accepting our choice to join PJM, the FERC directed AEP, ComEd, Midwest Independent Transmission System Operator (MISO) and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO.

In July 2004, AEP and PJM filed jointly with the FERC a hold-harmless proposal. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. The Michigan and Wisconsin utilities presented studies that show estimated adverse effects to utilities in the two states in the range of $60 million to $70 million over the term of the agreement for AEP and ComEd. A supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP and ComEd presented studies that show no adverse effects to the Michigan and Wisconsin utilities. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250 thousand that was approved by the FERC on March 7, 2005. On April 25, 2005, AEP and International Transmission Company in Michigan filed a settlement that resolves all hold-harmless issues for a one-time payment of $120 thousand that was approved by the FERC on June 24, 2005. On May 19, 2005, AEP and all remaining Michigan companies filed a settlement that resolves all hold-harmless issues for a one-time payment of approximately $2 million which was approved by the FERC on June 24, 2005.

The payment to the Michigan utilities will be deferred, as was the Wisconsin payment, as a PJM integration cost to be amortized over 15 years and recovery will be sought in future retail rate filings. Management believes that it is probable that these payments will ultimately be recovered from retail and wholesale customers. If the AEP East companies cannot recover these amortizations on a timely basis in their retail base rates, future results of operations and cash flows will be adversely affected.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called 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 SECA revenues of $32 million and $57 million for the second quarter and first half of 2005, respectively. In addition, we recognized $11 million of 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 and municipal, 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 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 proposed 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. This investigation provides AEP an opportunity to propose and support a new PJM rate regime that could mitigate losses from the elimination of T&O transmission rates and the discontinuance of the SECA rate collections.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, 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 or within the PJM and MISO Regions that compensates for AEP's T&O revenue losses, future results of operations, cash flows and financial condition would be adversely affected.

RTO Formation/Integration Costs

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs incurred to originally form a new RTO (the Alliance) and subsequently to join an existing RTO (PJM). In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The FERC approved our application and in January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years (the latter, consistent with a March 8, 2005 requested rate recovery period discussed below). The total amortization related to such costs was $1 million and $2 million in the second quarter and first half of 2005, respectively. As of June 30, 2005, the AEP East Companies have $34 million of deferred unamortized RTO formation/integration costs.

On March 8, 2005, AEP and two other utilities jointly filed a request with the FERC to recover the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. The FERC responded to the March 8, 2005 filing in an order on May 6, 2005 denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a Compliance Filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the Compliance Filing on May 27, 2005. On June 6, 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including to the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). AEP's rehearing request remains pending. At this time, management is unable to predict the likelihood of a favorable rehearing result.

On March 31, 2005, we also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed above). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of our deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs). The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

Until the AEP East Companies can adjust their retail rates to recover the amortization of both deferred costs, results of operations and cash flows will be adversely affected by the amortizations. If the FERC were to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs not billed by PJM, it would have an adverse impact on future results of operations and cash flows.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring and update the 2004 Annual Report.

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 additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues. 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 were increased by $14 million for CSPCo and $40 million for OPCo in the first half of 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo relate to 2004 environmental carrying costs and RTO costs.

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. If the RSP order was determined to be illegal under the Restructuring Legislation, as contended by the two intervenors, it would have an adverse effect on results of operations, cash flow 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.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through June 30, 2005, we incurred $83 million of such costs, and accordingly, we deferred $43 million of such costs for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

The stranded cost recovery process in Texas continues with the principal remaining component of the process being 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. 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, including unrecorded equity carrying costs and future unrecorded carrying costs through September 2005. This filing does not include a deduction for 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. Although it was determined that it was probable that the PUCT would make this adjustment in TCC's proceeding, we do not believe the adjustment is appropriate and will litigate the issue, if necessary. As a result, the filing was not reduced by the $238 million. The PUCT hearing is scheduled to begin on September 26, 2005. It is anticipated that the PUCT will issue a final order in the fourth quarter of 2005.

The Components of TCC's Recorded Net True-up Regulatory Asset (inclusive of provisions) recorded as of June 30, 2005 and December 31, 2004 are:

	TCC	
	June 30, 2005	**December 31, 2004**
	(in millions)	
Stranded Generation Plant Costs	$ 887	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(3)	(10)
Net Stranded Generation Costs	1,133	1,136
Carrying Costs on Stranded Generation Plant Costs	215	225
Net Stranded Generation Costs Designated for Securitization	1,348	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	102	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(209)	(212)
Net Other Recoverable True-up Amounts	315	287
Total Recorded Net True-up Regulatory Asset	$ 1,663	$ 1,648

The Components of TNC's Net True-up Regulatory Liability as of June 30, 2005 and December 31, 2004 are:

	TNC	
	June 30, 2005	**December 31, 2004**
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	$ (19)	$ (18)

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that net stranded generation costs should be reduced by the present value of deferred investment tax credits (ITC) and excess deferred federal income taxes applicable to generating assets. The nonaffiliated utility testified in its True-up Proceeding that acceleration of the sharing of deferred ITC with customers may be a violation of the Internal Revenue Code's normalization provisions. Management agrees with the nonaffiliated utility that the PUCT's acceleration of deferred ITC and excess deferred federal income taxes may be a violation of the normalization provisions. As a result, management has not included as a reduction of its net stranded generation costs the present value of TCC's generation-related deferred ITC of $70 million and the present value of excess deferred federal income taxes of $6 million in its true-up filing. Such amounts also are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table since to do so may be a normalization violation. The Internal Revenue Service (IRS) has issued proposed regulations that would make an exception to the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS has not issued final regulations, TCC filed a request for a private letter ruling from the IRS on June 28, 2005 to determine whether the PUCT's action would result in a normalization violation. A normalization violation could result in the repayment of TCC's accumulated deferred ITC on all property, not just generation property, which approximates $106 million as of June 30, 2005 and a loss of the ability to elect accelerated tax depreciation in the future. Management is unable to predict how the IRS will rule on the private letter ruling request and whether any PUCT order will adversely affect future results of operations and cash flows.

TCC Fuel Reconciliation

On April 14, 2005, the PUCT ruled that specific energy-only purchased power contracts included a capacity component, which is not recoverable in fuel rates. As a result of this decision, in the first quarter of 2005, TCC recorded a provision for over-recovered fuel of $3 million, inclusive of interest. Reflecting all of the decisions in the final order and the resultant provisions for refund, the deferred over-recovery balance was $209 million as of June 30, 2005, including accrued interest. TCC has filed a motion for rehearing on several items which was denied by operation of law on July 18, 2005. TCC will appeal the PUCT's decision to the courts in August 2005.

TCC Carrying Costs on Net True-up Regulatory Assets

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 the nonaffiliated utility's securitization proceeding discussed above, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal Income Taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. In the first half of 2005, TCC accrued carrying costs of $42 million which were partially offset by a first quarter adjustment of $27 million based on this order. The net increase of $15 million in carrying costs is included in Other Income on the accompanying Condensed Consolidated Statements of Income in the first half of 2005 inclusive of $21 million of carrying costs accrued in the second quarter of 2005.

In an April 2005 open meeting regarding another nonaffiliated utility's True-up Proceeding, the PUCT determined that the filed cost of debt did not establish a Weighted Average Cost of Capital (WACC) rate or an embedded debt rate because that utility's Unbundled Cost of Service (UCOS) case was based on a settlement that did not specifically address the debt rate. As a result, the other utility was required to use a lower rate to compute its carrying costs than its filed UCOS rate. With this precedent, TCC anticipates that it will be required to address the WACC issue. Although TCC's UCOS case was also settled, TCC's facts and circumstances differ from those of the nonaffiliated utility in that TCC's settlement included a WACC rate and the UCOS order approving the settlement included sufficient other information to determine the embedded debt rate in the settlement. Management, however, is unable to determine the probable outcome of this matter when or if it is adjudicated in TCC's True-up Proceeding. If the PUCT ultimately determines that a similar lower cost of debt 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 would have an adverse impact on future results of operations and cash flows. Through the second quarter of 2005, such reversal would approximate $60 million, of which $9 million would apply to amounts accrued in 2005 based upon TCC's weighted cost of debt in its 2001 excess earnings report.

Through June 30, 2005, TCC has computed carrying costs of $483 million, of which $302 million was recognized as income in 2004 and applied to years prior to 2005. Approximately $42 million was recognized as income in the first half of 2005 before the $27 million offsetting adjustment discussed above. The remaining equity component of the carrying costs of $166 million through June 30, 2005 will be recognized in income as collected.

TCC Unrefunded Excess Earnings

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. In the first half of 2005, TCC refunded an additional $7 million reducing its unrefunded excess earnings to $3 million. On July 15, 2005, the PUCT approved a preliminary order in the TCC true-up that ordered TCC to cease refunding excess earnings at the end of July 2005. The unrefunded balance of excess earnings, as of the end of July 2005, is estimated to be approximately $1 million and will be credited to the balance of stranded costs.

TCC True-up Proceeding

As discussed earlier, TCC made its true-up filing requesting $2.4 billion of stranded costs. Hearings are scheduled to start on September 26, 2005 and an order is projected to be issued during the fourth quarter of 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 (CTC) in the regulated T&D rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

The nonaffiliated utility's March 2005 order referred to above also provided for the present value of the cost free capital benefits of ADFIT associated with stranded generation costs to be offset against other recoverable true-up amounts when establishing the CTC. TCC estimates its present value ADFIT benefit to be $211 million based on its current net true-up regulatory asset. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT in the nonaffiliated utility's order and determined that the projected cash flows from the transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding.

We believe that our filed $2.4 billion request for recovery of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation and that our $1.7 billion recorded net true-up regulatory asset, inclusive of carrying costs at June 30, 2005, is probable of recovery at this time. However , we anticipate that other parties will contend in our proceeding that 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 an adverse effect on future results of operations, cash flows and possibly financial condition.

TNC True-Up Proceeding

In May 2005, the PUCT issued a favorable order, adopting the ALJ's recommendation regarding the post-reconciliation period off-system sales margins, but did not adopt his excess earnings recommendation. The PUCT stated that excess earnings would be addressed in the CTC filing scheduled to be filed in the third quarter of 2005. Based upon the ruling regarding off-system sales margins, TNC adjusted its deferred over-recovered fuel balance during the second quarter of 2005.

In 2004, TNC appealed to the state and federal courts the PUCT's order in its final fuel reconciliation covering the period from July 2000 through December 31, 2001 in which the PUCT disallowed approximately $30 million of fuel costs. In March 2005, the ALJ made certain recommendations regarding the deferred fuel balance resulting in an additional provision for refund of $1 million, which results in an over-recovery amount of $5 million. TNC will pursue vigorously its appeals, but cannot predict their outcome, however, the result of these appeals could affect the TNC true-up order issued by the PUCT in May 2005 discussed above.

5. <u>COMMITMENTS AND CONTINGENCIES</u>

As discussed in the Commitments and Contingencies note within our 2004 Annual Report, we continue to be involved in various legal matters. The 2004 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2004 Annual Report. The matters discussed in the 2004 Annual Report without significant changes in status since year-end include, but are not limited to, (1) carbon dioxide public nuisance claims, (2) nuclear matters, (3) construction and commitments, (4) potential uninsured losses, (5) shareholder lawsuits, (6) coal transportation dispute, and (7) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in our 2004 Annual Report.

Environmental

Federal EPA Complaint and Notice of Violation

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 is underway and closing arguments will be heard on September 22, 2005.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

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 are 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 complaint 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 in January 2005 and to the Federal EPA’s complaint in July 2005, denying the allegations and stating its defenses.

In August 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not “routine” maintenance, repair and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A settlement between Ohio Edison, the Federal EPA and other parties to the litigation will avoid further litigation and result in expenditures at its plant.

Other utility enforcement actions and current regulatory activities are discussed in detail in the Commitments and Contingencies note in the 2004 Annual Report. However, since the issuance of the August 2003 decision against Ohio Edison, several other courts have considered the issues of what constitutes "routine maintenance, repair, and replacement" for utility units, and whether increased hours of operation are the measure of an emissions increase, and each court has reached a conclusion that differs markedly from the decision in the Ohio Edison case. These decisions include the District Court opinion in the Duke Energy case issued later in August 2003, the District Court opinion in Alabama Power issued on June 3, 2005, and the Fourth Circuit Court of Appeals opinion affirming the dismissal of all claims against Duke Energy issued on June 15, 2005. In addition, on June 10, 2005, the Administrator of the Federal EPA rejected all of the petitions for reconsideration of the October 2003 "equipment replacement provision" rule that defines "routine replacement" under the new source review program to include the same types of activities challenged in the pending enforcement actions. Management therefore believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant.

In June 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On June 24, 2005, the United States Court of Appeals for the D.C. Circuit issued a decision affirming in part the new source review reform regulations adopted by the Federal EPA in December of 2002. The court upheld the Federal EPA's decision to apply an actual-to-future actual emissions test, utilizing a five-year look back period to establish actual baseline emissions for utilities and a ten-year period for other sources, and excluding increased emissions unrelated to a physical change from the projected emissions, including 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. The Court expressed no opinion on the conclusion reached by the Duke Energy court, and found that such issues could be better addressed in a specific factual context.

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.

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 SWEPCo's Welsh, Knox Lee and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. 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. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. 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 $228,312 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.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

Operational

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 has also 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 allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, 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. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. 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 has been 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 and a decision is pending.

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 has filed a petition for review of this Initial Decision, which the SEC has granted. The SEC is reviewing the Initial Decision.

Enron Bankruptcy

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

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

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in state court of Texas seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. On April 6, 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

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

In January 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of the 98% interest in HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain is dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

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

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

Enron Bankruptcy - Summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but were subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine. We will continue to defend vigorously each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. In December 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied in September 2004. Plaintiffs have filed a Motion for Class Certification. The defendants, including AEP and AEPES, filed their opposition to class certification in April 2005. Briefing on the issue of class certification was completed in May 2005. Discovery is continuing in the case with a closing date of December 31, 2005. Summary judgment motions are due in January 2006. We intend to continue to defend vigorously against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four of our subsidiaries, certain nonaffiliated energy companies and ERCOT. 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. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, sought leave to intervene as plaintiffs asserting similar claims. In June 2004, the Court dismissed all claims against the AEP companies. TCE has 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. 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. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us and claimed that we owed approximately $34 million. 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 and that BOM had acknowledged just prior to the termination and liquidation that it owed us approximately $68 million. We are claiming that BOM owes us at least $41 million related to previously recorded receivables on which we hold approximately $20 million of credit collateral. Discovery has ended and both parties filed motions for summary judgment on July 1, 2005. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows and financial condition.

6. GUARANTEES

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

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs generally cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. We issued all of these LOCs in our ordinary course of business. At June 30, 2005, the maximum future payments for all the LOCs were approximately $227 million with maturities ranging from July 2005 to April 2007. As the parent of the various subsidiaries that have issued these LOCs, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these LOCs are drawn.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $50 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At June 30, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and the first six months of 2005, we entered into several sale agreements. The status of certain sales agreements is discussed in Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.2 billion. There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At June 30, 2005, the maximum potential loss for this lease agreement was approximately $45 million ($29 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms for a maximum of twenty years. We intend to renew the lease for the full twenty years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At June 30, 2005, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year terms to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of structure.

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

ACQUISITIONS

Public Service Enterprise Group (PSEG) Waterford Energy LLC (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with PSEG Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio for $220 million. This transaction is contingent on the receipt of required regulatory approval from PUCO and is expected to close in the third quarter of 2005.

Monongahela Power Company (Utility Operations Segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, we agreed to terms of a transaction, which includes the transfer of Monongahela Power's Ohio customer base and the assets that serve those customers to CSPCo for an estimated sales price of approximately $55 million. The sale price will be adjusted based on book values of the acquired assets and liabilities at the closing date. We anticipate the purchase, subject to regulatory approval, to close late in the fourth quarter of 2005.

DISPOSITIONS COMPLETED AND ANTICIPATED BEING COMPLETED DURING 2005

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

In January 2005, we sold a 98% controlling interest in HPL, 30 BCF of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We retained a 2% ownership interest in HPL and provide certain transitional administrative services to the buyer. Although the assets have been legally transferred, it is not possible to determine all costs associated with the transfer until the BOA litigation is resolved. Accordingly, we have deferred the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $376 million as of June 30, 2005, which is reflected in Deferred Credits and Other on our accompanying Condensed Consolidated Balance Sheets and is subject to further purchase price true-up adjustments as defined in the contract. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a resulting inability to use the cushion gas (see "Enron Bankruptcy - Right to use of cushion gas agreements" section of Note 5). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008, the cushion gas arrangement and our 2% ownership interest.

We also have a put option expiring in 2006, which allows us to sell our remaining 2% interest to the buyer for approximately $16 million.

Pacific Hydro Limited (Investments - Other segment)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $88 million. The sale was contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. The sale was consummated on July 19, 2005 and we will recognize an estimated pretax gain of approximately $50 million.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement.

In March 2005, AEP and Centrica entered into a series of agreements resulting in the resolution of open issues related to the sale and the disputed ESM payments for 2003 and 2004. Also in March 2005, we received payments of $45 million and $70 million related to the ESM payments for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in the first quarter of 2005, which is reflected in Other Income on our accompanying Condensed Consolidated Statements of Income. The ESM payments for 2005 and 2006 are contingent on Centrica's future operating results and are capped at $70 million and $20 million, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap.

Texas Plants - Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately

$43 million (subject to closing adjustments) to an unrelated party. By May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements are currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, in our Condensed Consolidated Balance Sheets at June 30, 2005 and December 31, 2004. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of AEP's Power Pool which includes all of the generation facilities owned by our Registrant Subsidiaries.

Texas Plants - South Texas Project (Utility Operations segment)

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

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been reclassified for the three and six-month periods ended June 30, 2005 and 2004 as shown in the following tables:

For the three months ended June 30, 2005 and 2004:

	SEEBOARD (a)	U.K. Operations (b)	Total
		(in millions)	
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income (Loss)	-	-	-
2005 Income (Loss) After tax	3	-	3

	Pushan Power Plant	LIG (c)	U.K. Operations	Total
		(in millions)		
2004 Revenue	$ -	$ 4	$ 34	$ 38
2004 Pretax Income (Loss)	-	2	(80)	(78)
2004 Income (Loss) After tax	(1)	2	(52)	(51)

For the six months ended June 30, 2005 and 2004:

	SEEBOARD (a)	U.K. Operations (b)	Total
		(in millions)	
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income (Loss)	-	(8)	(8)
2005 Income (Loss) After tax	9	(5)	4

	Pushan Power Plant	LIG (c)	U.K. Operations	Total
		(in millions)		
2004 Revenue	$ 10	$ 164	$ 75	$ 249
2004 Pretax Income (Loss)	9	1	(99)	(89)
2004 Income (Loss) After tax	5	1	(64)	(58)

(a) Includes a tax adjustment related to the sale of SEEBOARD.
(b) Relates primarily to purchase price true-up adjustments.
(c) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.

For the six months ended June 30, 2004, the net increase in cash and cash equivalents of discontinued operations was $2 million, primarily from the cash flows from operating activities of the discontinued operations.

ASSETS HELD FOR SALE

The assets and liabilities of the entities that were classified as held for sale at June 30, 2005 and December 31, 2004 are as follows:

	Texas Plants	
	June 30, 2005	December 31, 2004
Assets:	(in millions)	
Other Current Assets	$ 2	$ 24
Property, Plant and Equipment, Net	44	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale	$ 46	$ 628
Liabilities:		
Regulatory Liabilities	$ 1	$ 1
Asset Retirement Obligations	-	249
Total Liabilities Held for Sale	$ 1	$ 250

8. BENEFIT PLANS

Components of Net Periodic Benefit Costs

The following table provides the components of our net periodic benefit cost for the following plans for the three and six months ended June 30, 2005 and 2004:

Three Months Ended June 30, 2005 and 2004:	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
		(in millions)		
Service Cost	$ 23	$ 21	$ 10	$ 10
Interest Cost	56	56	26	29
Expected (Return) on Plan Assets	(78)	(72)	(22)	(20)
Amortization of Transition Obligation	-	1	7	7
Amortization of Net Actuarial Loss	14	4	7	9
Net Periodic Benefit Cost	$ 15	$ 10	$ 28	$ 35

Six Months Ended June 30, 2005 and 2004:	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
		(in millions)		
Service Cost	$ 46	$ 43	$ 21	$ 20
Interest Cost	112	112	53	58
Expected (Return) on Plan Assets	(155)	(144)	(45)	(40)
Amortization of Transition Obligation	-	1	14	14
Amortization of Net Actuarial Loss	27	8	14	18
Net Periodic Benefit Cost	$ 30	$ 20	$ 57	$ 70

9. BUSINESS 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 U.K., LIG and Jefferson Island Storage & Hub, and the sale in January 2005 of a 98% interest in the HPL assets. Consequently, the significance of our three Investments segments is declining.

Our 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 - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.

Operations of Louisiana Intrastate Gas, including Jefferson Island Storage, were classified as Discontinued Operations during 2003 and were sold during the third and fourth quarters of 2004, respectively. We sold our 98% interest in HPL during the first quarter of 2005.

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.

UK Operations were classified as Discontinued Operations during 2003 and were sold during the third quarter of 2004.

Investments - Other

- Bulk commodity barging operations, wind farms, independent power producers and other energy supply related businesses.

Four independent power producers were sold during the third and fourth quarters of 2004.

With the sale of a 98% controlling interest in HPL during January 2005, we have substantially completed planned disposals of all significant noncore assets. Accordingly, effective with the quarter ended March 31, 2005, certain subsidiaries representing shared service functions and costs were reclassified to Utility Operations and Investments - Other from either Investments - Other or All Other. Such reclassifications were deemed necessary given the remaining compositions of the individual segments and the nature of the shared service functions and costs.

The tables below present segment income statement information for the three and six months ended June 30, 2005 and 2004 and balance sheet information as of June 30, 2005 and December 31, 2004. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
Three Months Ended June 30, 2005	**Utility Operations**	**Gas Operations**	**UK Operations**	**Other**	**All Other (a)**	**Reconciling Adjustments (b)**	**Consolidated**
			(in millions)				
Revenues from:							
External Customers	$ 2,649	$ 19	$ -	$ 105	$ -	$ -	$ 2,773
Other Operating Segments	19	(17)	-	3	-	(5)	-
Total Revenues	$ 2,668	$ 2	$ -	$ 108	$ -	$ (5)	$ 2,773
Income (Loss) Before Discontinued Operations	$ 247	$ (2)	$ -	$ (1)	$ (26)	$ -	$ 218
Discontinued Operations, Net of Tax	-	-	-	3	-	-	3
Net Income (Loss)	$ 247	$ (2)	$ -	$ 2	$ (26)	$ -	$ 221
As of June 30, 2005							
Total Property, Plant and Equipment	$ 36,736	$ 2	$ -	$ 834	$ 3	$ -	$ 37,575
Accumulated Depreciation and Amortization	14,580	1	-	100	1	-	14,682
Total Property, Plant and Equipment - Net	$ 22,156	$ 1	$ -	$ 734	$ 2	$ -	$ 22,893
Total Assets	$ 31,965	$ 1,028	$ 574(c)	$ 421	$9,269	$ (9,318)	$ 33,939

Assets Held for Sale	46	-	-	-	-	-	46

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.
(c) Total Assets of $574 million for the Investments-UK Operations segment include $553 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $21 million in assets represents cash equivalents along with value-added tax receivables.

		Investments					
Three Months Ended June 30, 2004	**Utility Operations**	**Gas Operations**	**UK Operations**	**Other**	**All Other (a)**	**Reconciling Adjustments (b)**	**Consolidated**
				(in millions)			
Revenues from:							
External Customers	$ 2,508	$ 779	$ -	$ 124	$ -	$ -	$ 3,411
Other Operating Segments	37	15	-	7	(2)	(57)	-
Total Revenues	$ 2,545	$ 794	$ -	$ 131	$ (2)	$ (57)	$ 3,411
Income (Loss) Before Discontinued Operations	$ 184	$ (4)	$ -	$ (4)	$ (25)	$ -	$ 151
Discontinued Operations, Net of Tax	-	2	(52)	(1)	-	-	(51)
Net Income (Loss)	$ 184	$ (2)	$ (52)	$ (5)	$ (25)	$ -	$ 100
As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,006	$ 445	$ -	$ 832	$ 3	$ -	$ 37,286
Accumulated Depreciation and Amortization	14,355	43	-	86	1	-	14,485
Total Property, Plant and Equipment - Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,175	$ 1,789	$ 221(c)	$2,071	$8,093	$ (9,686)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.
(c) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

		Investments					
					All	**Reconciling**	

Six Months Ended June 30, 2005	Utility Operations	Gas Operations	UK Operations	Other	Other (a)	Adjustments (b)	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 5,186	$ 376	$ -	$ 194	$ -	$ -	$ 5,756
Other Operating Segments	96	(90)	-	6	1	(13)	-
Total Revenues	$ 5,282	$ 286	$ -	$ 200	$ 1	$ (13)	$ 5,756
Income (Loss) Before Discontinued Operations	$ 600	$ 8	$ -	$ 4	$ (40)	$ -	$ 572
Discontinued Operations, Net of Tax	-	-	(5)	9	-	-	4
Net Income (Loss)	$ 600	$ 8	$ (5)	$ 13	$ (40)	$ -	$ 576
As of June 30, 2005							
Total Property, Plant and Equipment	$ 36,736	$ 2	$ -	$ 834	$ 3	$ -	$ 37,575
Accumulated Depreciation and Amortization	14,580	1	-	100	1	-	14,682
Total Property, Plant and Equipment - Net	$ 22,156	$ 1	$ -	$ 734	$ 2	$ -	$ 22,893
Total Assets	$ 31,965	$ 1,028	$ 574(c)	$ 421	$9,269	$ (9,318)	$ 33,939
Assets Held for Sale	46	-	-	-	-	-	46

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

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

(c) Total Assets of $574 million for the Investments-UK Operations segment include $553 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $21 million in assets represents cash equivalents and third party receivables.

Six Months Ended June 30, 2004	Utility Operations	Investments: Gas Operations	Investments: UK Operations	Investments: Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 5,089	$ 1,431	$ -	$ 255	$ -	$ -	$ 6,775
Other Operating Segments	58	39	-	27	4	(128)	-
Total Revenues	$ 5,147	$ 1,470	$ -	$ 282	$ 4	$ (128)	$ 6,775
Income (Loss) Before Discontinued Operations	$ 488	$ (14)	$ -	$ -	$ (34)	$ -	$ 440
Discontinued Operations, Net of Tax	-	1	(64)	5	-	-	(58)
Net Income (Loss)	$ 488	$ (13)	$ (64)	$ 5	$ (34)	$ -	$ 382

As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,006	$ 445	$ -	$ 832	$ 3	$ -	$ 37,286
Accumulated Depreciation and Amortization	14,355	43	-	86	1	-	14,485
Total Property, Plant and Equipment - Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,175	$ 1,789	$ 221(c)	$2,071	$8,093	$ (9,686)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.

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

(c) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

10. INCOME TAXES

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In the second quarter of 2005, we reversed deferred state income tax liabilities of $61 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Taxes and, for the Ohio companies, established a regulatory liability for $57 million pending ratemaking treatment in Ohio.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 is expected to be $2 million.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0 % to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance policies; all of which will not have a material impact on future results of operations and cash flows.

11. FINANCING ACTIVITIES

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2005 are shown in the tables below.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)		
Issuances:				

AEP	Senior Unsecured Notes	$ 345	4.709%	2007
APCo	Senior Unsecured Notes	200	4.95%	2015
APCo	Senior Unsecured Notes	150	4.40%	2010
APCo	Senior Unsecured Notes	250	5.00%	2017
OPCo	Installment Purchase Contracts	54	Variable	2029
OPCo	Installment Purchase Contracts	164	Variable	2028
PSO	Senior Unsecured Notes	75	4.70%	2011
SWEPCo	Senior Unsecured Notes	150	4.90%	2015
TCC	Installment Purchase Contracts	162	Variable	2030
TCC	Installment Purchase Contracts	120	Variable	2028
Non-Registrant:				
AEP Subsidiary	Notes Payable	6	Variable	2009
Total Issuances		$ 1,676(a)		

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

(a) Amount indicated on statement of cash flows of $1,660 million is net of issuance costs and unamortized premium or discount.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate	Due Date
Retirements and Principal Payments:				
AEP	Senior Unsecured Notes	$ 550	6.125%	2006
AEP	Senior Unsecured Notes	345	5.75%	2007
AEP	Other Debt	6	Variable	2007
AEP and Subsidiaries	Other	12(b)	Variable	Various
APCo	First Mortgage Bonds	50	8.00%	2005
APCo	First Mortgage Bonds	30	6.89%	2005
APCo	First Mortgage Bonds	45	8.00%	2025
APCo	Senior Unsecured Notes	450	4.80%	2005
OPCo	Installment Purchase Contracts	102	6.375%	2029
OPCo	Installment Purchase Contracts	80	Variable	2028
OPCo	Installment Purchase Contracts	36	Variable	2029
OPCo	Notes Payable	3	6.81%	2008
OPCo	Notes Payable	3	6.27%	2009
PSO	First Mortgage Bonds	50	6.50%	2005
SWEPCo	Notes Payable	3	4.47%	2011

SWEPCo	Notes Payable	2	Variable	2008
TCC	Senior Unsecured Notes	150	3.00%	2005
TCC	Senior Unsecured Notes	100	Variable	2005
TCC	Securitization Bonds	29	3.54%	2005
Non-Registrant:				
AEP Subsidiaries	Notes Payable	6	Variable	Various
Total Retirements		$ 2,052(c)		

(b) Amount reflects mark-to-market of risk management contracts related to long-term debt.

(c) The cash used for retirement of long-term debt indicated on statement of cash flows of $2,040 million does not include $12 million related to the mark-to-market of risk management contracts.

Preferred Stock Redemption

In January 2005, the following outstanding shares of preferred stock were redeemed:

Company	**Series**	**Number of Shares Redeemed**	**Amount**
			(in millions)
I&M	5.900%	132,000	$ 13
I&M	6.250%	192,500	19
I&M	6.875%	157,500	16
I&M	6.300%	132,450	13
OPCo	5.900%	50,000	5
			$ 66

Common Stock Repurchase

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 plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May and we received a purchase price adjustment of $6.45 million based on the actual cost of the shares repurchased.

Remarketing of Senior Notes

In June 2005, we remarketed and settled $345 million of AEP's 5.75% senior notes at a new interest rate of 4.709%. The senior notes will mature on August 16, 2007. The senior notes were originally issued in June 2002 in connection with our 9.25% equity units. We did not receive any proceeds from the mandatory remarketing. On August 16, 2005, the forward purchase contracts, which formed part of the equity units, will settle and holders will be required to purchase 8.4 million AEP common shares, based on the current stock price, which will be issued at that time.

12. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As result of a company-wide staffing and budget review 466 positions were identified for elimination. Accordingly, approximately $24 million pretax severance benefits expense was recorded (primarily in Maintenance and Other Operation) in the second quarter of 2005. The following table shows the total expense recorded and the remaining accrual (reflected primarily in Current Liabilities - Other) as of June 30, 2005:

Amount

	(in millions)
Total Expense	$ 24
Less: Total Payments	3
Remaining Accrual at June 30, 2005	$ 21

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Operating revenues are derived from the sale of our share of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Fluctuations in Net Income are a result of terms in the unit power agreements which allow for the monthly calculation of return on total capital, largely dependent on the percentage of plant assets in service.

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$ 1.5
Change in Gross Margin:		
Wholesale Sales		0.5
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	0.1	
Depreciation and Amortization	(0.2)	
Interest Charges	0.2	
Total Change in Operating Expenses and Other		0.1
Income Tax Expense		-
Second Quarter of 2005 Net Income		$ 2.1

Gross margin increased $0.5 million primarily due to a higher return on capital as a result of an increase in the percentage of plant assets in service with the completion of low NO_x burner installation in 2004. Gross margin and Net Income fluctuate consistent with the plant in service percentage in accordance with the unit power agreements.

The decrease in Other Operation and Maintenance expenses resulted from decreased outages and the related costs compared to prior year.

Depreciation and Amortization increased reflecting increased depreciable generating plant.

Interest Charges decreased due to lower borrowings from the Utility Money Pool.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were (11.3)% and (19.7)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences and state income taxes. The change in the effective tax rate is primarily due to lower state and local income taxes and changes in various permanent and flow-through temporary differences.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income
(in millions)

Six Months Ended June 30, 2004 Net Income		$ 3.3
Change in Gross Margin:		
Wholesale Sales		(1.9)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	3.9	
Depreciation and Amortization	(0.4)	
Taxes Other Than Income Taxes	(0.2)	
Nonoperating Income and Expenses, Net	0.1	
Total Change in Operating Expenses and Other		3.4
Income Tax Expense		(0.2)
Six Months Ended June 30, 2005 Net Income		$ 4.6

Gross margin decreased $1.9 million primarily due to a decrease in operation and maintenance expense partially offset by the impact of the higher percentage of plant assets in service on return on capital discussed above. Gross margin fluctuates consistent with operation and maintenance expense in accordance with the unit power agreements.

The decrease in Other Operation and Maintenance expenses resulted from decreased outages and the related costs compared to prior year. In 2004, Rockport Plant Unit 2 was shut down for planned boiler inspection and repairs from early February through early April.

Depreciation and Amortization increased reflecting increased depreciable generating plant.

The increase in Taxes Other Than Income Taxes reflects increased real and personal property taxes of $0.2 million.

Income Taxes

The effective tax rates for the first six months of 2005 and 2004 were (3.7)% and (13.9)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences and state income taxes. The change in the effective tax rate is primarily due to lower state and local income taxes and changes in various permanent and flow-through temporary differences.

Off-Balance Sheet Arrangement

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

Significant Factors

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

Critical Accounting Estimates

See “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES	$ 65,082	$ 56,348	$ 131,628	$ 111,630
OPERATING EXPENSES				
Fuel for Electric Generation	33,233	25,036	68,368	46,434
Rent - Rockport Plant Unit 2	17,071	17,071	34,142	34,142
Other Operation	3,075	2,665	5,460	5,155
Maintenance	2,272	2,790	3,990	8,190
Depreciation and Amortization	5,989	5,772	11,945	11,506
Taxes Other Than Income Taxes	1,051	942	2,075	1,886
Income Taxes	666	699	1,602	1,397
TOTAL	63,357	54,975	127,582	108,710
OPERATING INCOME	1,725	1,373	4,046	2,920
Nonoperating Income	84	5	84	29
Nonoperating Expenses	49	80	113	149
Nonoperating Income Tax Credit	877	947	1,768	1,804
Interest Charges	564	739	1,196	1,271
NET INCOME	$ 2,073	$ 1,506	$ 4,589	$ 3,333

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
BALANCE AT BEGINNING OF PERIOD	$ 25,813	$ 22,006	$ 24,237	$ 21,441
Net Income	2,073	1,506	4,589	3,333
Cash Dividends Declared	939	1,261	1,879	2,523
BALANCE AT END OF PERIOD	$ 26,947	$ 22,251	$ 26,947	$ 22,251

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 681,917	$ 681,254
General	3,937	3,739
Construction Work in Progress	6,760	7,729
Total	692,614	692,722
Accumulated Depreciation and Amortization	376,111	368,484
TOTAL - NET	316,503	324,238
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	24,159	23,078
Fuel	11,426	16,404
Materials and Supplies	6,675	5,962
Prepayments	26	-
TOTAL	42,286	45,444
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,377	4,496
Asset Retirement Obligations	1,214	1,117
Deferred Property Taxes	2,507	557
Other Deferred Charges	412	422
TOTAL	8,510	6,592
TOTAL ASSETS	$ 367,418	$ 376,393

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $1,000 par value per share:		
Authorized and Outstanding - 1,000 shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	23,434
Retained Earnings	26,947	24,237
Total Common Shareholder's Equity	51,381	48,671
Long-term Debt	44,824	44,820
TOTAL	96,205	93,491
CURRENT LIABILITIES		
Advances from Affiliates	24,621	26,915
Accounts Payable:		
General	708	443
Affiliated Companies	15,235	17,905
Taxes Accrued	6,764	8,806
Interest Accrued	911	911
Obligations Under Capital Leases	289	210
Rent Accrued - Rockport Plant Unit 2	4,963	4,963
Other	348	73
TOTAL	53,839	60,226
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	22,990	24,762
Regulatory Liabilities:		
Asset Removal Costs	27,104	25,428
Deferred Investment Tax Credits	44,582	46,250
SFAS 109 Regulatory Liability, Net	12,245	12,852
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	97,119	99,904
Obligations Under Capital Leases	12,070	12,264
Asset Retirement Obligations	1,264	1,216
TOTAL	217,374	222,676
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 367,418	$ 376,393

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 4,589	$ 3,333
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	11,945	11,506
Deferred Income Taxes	(2,379)	(1,319)
Deferred Investment Tax Credits	(1,668)	(1,668)
Deferred Property Taxes	(1,950)	(1,632)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(2,785)	(2,785)
Change in Other Noncurrent Assets	(1,296)	(67)
Change in Other Noncurrent Liabilities	1,534	73
Changes in Components of Working Capital:		
Accounts Receivable	(1,081)	752
Fuel, Materials and Supplies	4,265	(4,011)
Accounts Payable	(2,405)	(2,226)
Taxes Accrued	(2,042)	4,457
Other Current Assets	(26)	(21)
Other Current Liabilities	354	80
Net Cash Flows From Operating Activities	7,055	6,472
INVESTING ACTIVITIES		
Construction Expenditures	(2,882)	(9,815)
Net Cash Flows Used For Investing Activities	(2,882)	(9,815)
FINANCING ACTIVITIES		
Changes in Advances from Affiliates, Net	(2,294)	5,866
Dividends Paid	(1,879)	(2,523)
Net Cash Flows From (Used For) Financing Activities	(4,173)	3,343
Net Increase in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $1,063,000 and $1,138,000 and for income taxes was $8,080,000 and $570,000 in 2005 and 2004, respectively. Noncash acquisitions under capital leases were $26,000 and $14,000 in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income (in millions)

Second Quarter of 2004 Net Income		$ -
Changes in Gross Margin:		
Texas Supply	2	
Texas Wires	8	
Off-system Sales	(4)	
Transmission Revenues	(1)	
Total Change in Gross Margin		5
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	22	
Depreciation and Amortization	(7)	
Taxes Other Than Income Taxes	2	
Carrying Costs on Stranded Cost Recovery	20	
Total Change in Operating Expenses and Other		37
Income Tax Expense		(14)
Second Quarter of 2005 Net Income		$ 28

Net Income increased to $28 million in the second quarter of 2005. The key drivers of the increase were a net decrease in Other Operation and Maintenance of $22 million and increased Carrying Costs on Stranded Cost Recovery of $20 million.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins were $2 million higher primarily due to a provision for refund decrease in 2004 of $52 million as a result of the 2004 final fuel reconciliation true-up, lower fuel expense of $77 million, and an increase in realized dedicated gas revenue of $6 million. The increase in Texas Supply margins was offset by the loss of revenue from Centrica, our largest REP customer, of $96 million, loss of ERCOT Reliability Must Run (RMR) margins of $9 million and decreased ERCOT Energy sales of $11 million. Also contributing to the offset of higher Texas Supply margins were the loss of capacity sales of $9 million due to the sale of certain generation plants and a decrease of $6 million of affiliated REP sales due to loss of customers for AEP Texas C&I.
- Wires revenues increased $8 million primarily due to an increase in sales volumes of 7% resulting partly from a 12% increase in cooling degree days.
- Margins from Off-system Sales decreased $4 million primarily due to lower optimization activity.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $22 million primarily due to a $9 million decrease in power plant operations and an $11 million decrease in power plant maintenance both due to the sale of certain generation plants along with a $2 million decrease in employee-related expenses.
- Depreciation and Amortization expense increased $7 million primarily due to the recovery and amortization of securitized assets.
- Taxes Other Than Income Taxes decreased $2 million primarily due to lower property-related taxes as a result of the sale of certain generation plants.
- Carrying Costs on Stranded Cost Recovery of $20 million were recorded in the second quarter of 2005.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were 21.8% and 94.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The change in the effective tax rate for the comparative period is primarily due to pretax income and consolidated tax savings from Parent, offset in part by federal income tax adjustments.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income (in millions)

Six Months Ended June 30, 2004 Net Income		$ 29
Changes in Gross Margin:		
Texas Supply	(33)	
Texas Wires	9	
Off-system Sales	(5)	
Other Revenues	(9)	
Total Change in Gross Margin		(38)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	30	
Depreciation and Amortization	(7)	
Taxes Other Than Income Taxes	2	
Carrying Costs on Stranded Cost Recovery	15	
Nonoperating Income and Expense, Net	(6)	
Interest Charges	6	
Total Change in Operating Expenses and Other		40
Income Tax Expense		(1)
Six Months ended June 30, 2005 Net Income		$ 30

Net Income remained relatively flat for the six months ended June 30, 2005 compared to the six months ended June 30, 2004.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins were $33 million lower primarily due to the loss of revenue from Centrica, our largest REP customer, of $172 million, loss of ERCOT RMR margins of $16 million and decreased ERCOT Energy sales of

$14 million. Also contributing to the lower Texas Supply margins were the loss of capacity sales of $17 million due to the sale of certain generation plants and a decrease of $7 million of affiliated REP sales due to loss of customers for AEP Texas C&I. These decreases were partially offset by a decrease in 2004 for provision for refund of $62 million due to the 2004 final fuel reconciliation true-up and lower fuel expense of $134 million.

- Texas Wires revenue increased $9 million primarily due to an increase in sales volumes of 4% due in large part to increased degree days.
- Margins from Off-system Sales decreased $5 million primarily due to lower optimization activity.
- Other Revenues for 2005 decreased $9 million primarily due to a prior year adjustment in 2004 for affiliated OATT and ancillary services resulting from revised ERCOT data received for the years 2001 through 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $30 million primarily due to a $14 million decrease in power plant operations and a $10 million decrease in power plant maintenance both due to the sale of certain generation plants, and a $9 million decrease in administrative, general and employee- related expenses offset in part by slightly higher transmission and distribution-related expenses.
- Depreciation and Amortization expense increased $7 million primarily related to the recovery and amortization of securitized assets.
- Taxes Other Than Income Taxes decreased $2 million primarily due to lower property-related taxes as a result of the sale of certain generation plants.
- Carrying Costs on Stranded Cost Recovery increased $15 million. Carrying Costs on Stranded Cost Recovery of $42 million were recorded in the first six months of 2005 offset by an adjustment of $27 million for prior years. The adjustment related to a nonaffiliated utility's securitization proceeding in which the PUCT issued an order in March 2005 that resulted in a reduction in the nonaffiliated utility's carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes on net stranded cost and other true-up items retroactively applied to January 1, 2004.
- Nonoperating Income and Expense, Net decreased $6 million primarily due to $14 million of income in 2004 relating to risk management contracts which expired in December 2004 offset by higher net revenue from third party nonutility construction projects and a decrease in donation expense.
- Interest Charges decreased $6 million primarily due to the defeasance of First Mortgage Bonds in 2004 and the resultant deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust, long-term debt maturities and other financing activities.

Income Taxes

The effective tax rates for the six months ended 2005 and 2004 were 19.0% and 18.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the six months ended June 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ -	$ 760
Cash Flows From (Used For):		
Operating Activities	(109,779)	118,275
Investing Activities	144,833	(163,139)
Financing Activities	(32,960)	49,914
Net Increase in Cash and Cash Equivalents	2,094	5,050
Cash and Cash Equivalents at End of Period	$ 2,094	$ 5,810

Operating Activities

Our Net Cash Flows Used For Operating Activities were $110 million for the first six months of 2005. We produced income of $30 million during the period including noncash expense items of $65 million for Depreciation and Amortization and $(83) million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relate to a number of items; the most significant are decreases in Accounts Payable and Taxes Accrued offset in part by a decrease in Accounts Receivable, Net. Accounts Payable decreased $63 million while Accounts Receivable, Net decreased $46 million primarily due to energy related system sales. Accounts Payable also had an additional decrease related to the sale of certain generations plants. Taxes Accrued decreased $69 million primarily as a result of taxes remitted to the government related to prior year and current year tax accruals.

Our Net Cash Flows From Operating Activities were $118 million for the first six months of 2004. We produced income of $29 million during the period including noncash expense items of $58 million for Depreciation and Amortization and $60 million for Over/Under Fuel Recovery. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in these asset and liability accounts relates to a number of items; the most significant are increases in Taxes Accrued and Accounts Payable offset by an increase in Accounts Receivable, Net. Taxes Accrued increased $31 million primarily due to taxes that were accrued during the first six months of 2004 in excess of the amount remitted to the government. Accounts Payable increased $19 million while Accounts Receivable, Net increased $27 million primarily due to increased energy related system sales transactions. In addition, the estimated retail clawback adjustment slightly offset the increase of Accounts Receivable, Net.

Investing Activities

Net Cash Flows From Investing Activities were $145 million in 2005 primarily due to $314 million of net proceeds from the sale of the STP nuclear plant. The proceeds are partially offset by an increase of $107 million in Other Cash Deposits, Net related to the issuance of new pollution control revenue bonds which will be used specifically for refinancing activities in the third quarter of 2005 and also by Construction Expenditures of $61 million related to projects for improved transmission and distribution service reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $150 million.

Net Cash Flows From Investing Activities were $163 million in 2004 primarily due to Construction Expenditures of $49 million related to projects for improved transmission and distribution service reliability and $115 million in cash deposits for future long-term debt retirement.

Financing Activities

Net Cash Flows Used For Financing Activities of $33 million in 2005 were due to the retirement of Senior Unsecured Notes Payable and Securitization Bonds of $279 million along with the payment of dividends. This was partially offset by a $120 million increase in Advances from Affiliates and issuances of Installment Purchase Contracts of $277 million, $120 million of which was issued for the purpose of funding the July 1, 2005 retirement of our $120 million, 6.0% Installment Purchase Contracts.

Net Cash Flows From Financing Activities of $50 million in 2004 were primarily due to becoming a net borrower as opposed to lender in the Utility Money Pool. This was offset by the retirement of $35 million of long-term debt and payment of dividends.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contract	$ 111,700	Variable	2030
Installment Purchase Contract	50,000	Variable	2030
Installment Purchase Contract	60,000 (a)	Variable	2028
Installment Purchase Contract	60,265 (a)	Variable	2028

(a) - represents issuance in advance of retirement $120 million, 6.0% Installment Purchase Contracts on July 1, 2005.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes Payable	$ 150,000	3.00	2005
Senior Unsecured Notes Payable	100,000	Variable	2005
Securitization Bonds	29,386	3.54	2005

Liquidity

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

Summary Obligation Information

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

Significant Factors

Texas Restructuring

The principal remaining component of the stranded cost recovery process in Texas is the PUCT's determination and approval of our net stranded generation costs and other recoverable true-up items including carrying costs in our true-up filing. The PUCT approved our request to file our True-up Proceeding after the sales of our interest in STP, with only the ownership interest in Oklaunion remaining to be settled. On May 19, 2005, the sales of our interest in STP closed. On May 27, 2005, we filed our true-up request seeking recovery of $2.4 billion of net stranded costs and other true-up items which we believe the Texas Restructuring Legislation allows. Our request includes unrecorded equity carrying costs through May 27, 2005, all future carrying costs through September 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 is scheduled to begin on September 26, 2005. It is anticipated that the PUCT will issue a final order in the fourth quarter of 2005.

We continue to accrue carrying costs on our net true-up regulatory asset at the embedded 8.12% debt component rate and will continue to do so until we recover our 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 half of 2005, we began to accrue carrying costs based on this order. Through June 30, 2005, we have computed carrying costs of $483 million, of which we have recognized $317 million to-date. The equity component of the carrying costs which totals $166 million through June 30, 2005 will be recognized in income as collected.

In an April 2005 PUCT open meeting regarding another nonaffiliated utility's True-up Proceeding, the other utility was required to use a lower rate to compute its carrying costs than its filed unbundled cost of service rate. Our facts differ from the other utility's; however, if the PUCT ultimately determines that a similar lower rate be used by us to calculate carrying costs on our stranded cost balance, a portion of carrying costs previously recorded would have to be reversed and would have an adverse impact on our future results of operations and cash flows. Through June 30, 2005, such reversal would approximate $60 million, of which $9 million would apply to amounts accrued in 2005.

When the True-up Proceeding is completed, we intend 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 the 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 $2.4 billion request for recovery of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation and that our $1.7 billion recorded net true-up regulatory asset, inclusive of carrying costs at June 30, 2005, is probable of recovery at this time. However, we anticipate that other parties will contend in our proceeding that 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 our 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 an adverse effect on our future results of operations, cash flows and possibly financial condition.

Rate Case

We have an on-going T&D rate review before the PUCT. In that rate review, the PUCT has decided all issues except the amount of affiliate expenses to include in revenue requirements. Through an oral ruling, the PUCT approved the nonunanimous settlement filed in June 2005 that provides for an $11 million disallowance of affiliate expenses which, when combined with the previous decisions, results in a total reduction in our annual base rates of $9 million. A draft final order has been issued reflecting the $9 million reduction in our annual base rates. This reduction in our annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. It is anticipated that the PUCT will approve the final written order at its August 2005 open meeting. If the final written order differs from the draft order, it could impact our projected annual pretax earnings effect.

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	9,701
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(3,721)
Fair Value of New Contracts When Entered During the Period (b)		74
Net Option Premiums Paid/(Received) (c)		(11)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(3,427)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		2,616
Net Cash Flow Hedge Contracts (f)		(558)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	2,058

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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, 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 Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Condensed Consolidated Balance Sheets
As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 3,995	$ 22	$ 4,017
Noncurrent Assets	4,977	6	4,983
Total MTM Derivative Contract Assets	8,972	28	9,000
Current Liabilities	(3,737)	(535)	(4,272)
Noncurrent Liabilities	(2,619)	(51)	(2,670)
Total MTM Derivative Contract Liabilities	(6,356)	(586)	(6,942)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,616	$ (558)	$ 2,058

(a) Does not include Cash Flow 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (667)	$ (5)	$ 529	$ -	$ -	$ -	$ (143)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,427	1,809	598	648	-	-	4,482
Prices Based on Models and Other Valuation Methods (b)	(728)	(1,291)	(537)	(57)	407	483	(1,723)
Total	$ 32	$ 513	$ 590	$ 591	$ 407	$ 483	$ 2,616

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

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

(c) There is a mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $290 thousand of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 657
Changes in Fair Value (a)	(737)
Reclassifications from AOCI to Net Income (b)	(277)
Ending Balance June 30, 2005	$ (357)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $329 thousand loss.

Credit Risk

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

VaR Associated with Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$74	$88	$43	$25	$157	$511	$220	$75

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $87 million and $120 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 184,793	$ 257,053	$ 366,987	$ 525,911
Sales to AEP Affiliates	5,302	12,896	10,266	31,026
TOTAL	190,095	269,949	377,253	556,937
OPERATING EXPENSES				
Fuel for Electric Generation	4,012	20,806	10,087	43,912
Fuel from Affiliates for Electric Generation	21	59,977	44	100,176
Purchased Electricity for Resale	9,996	16,468	25,366	26,554
Purchased Electricity from AEP Affiliates	-	1,938	-	6,011
Other Operation	67,549	78,066	133,209	153,507
Maintenance	12,433	23,709	29,472	39,113
Depreciation and Amortization	35,434	28,879	64,720	57,976
Taxes Other Than Income Taxes	20,923	23,157	43,454	45,214
Income Taxes (Credits)	(1,312)	(6,388)	149	5,618
TOTAL	149,056	246,612	306,501	478,081
OPERATING INCOME	41,039	23,337	70,752	78,856
Carrying Costs on Stranded Cost Recovery	19,938	-	14,797	-
Nonoperating Income	18,260	12,061	34,556	24,163
Nonoperating Expenses	8,987	2,648	24,124	7,756
Nonoperating Income Tax Expense	9,240	880	6,755	860
Interest Charges	32,642	32,211	59,721	65,340
NET INCOME (LOSS)	28,368	(341)	29,505	29,063
Preferred Stock Dividend Requirements	61	61	121	121
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 28,307	$ (402)	$ 29,384	$ 28,942

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 55,292	$ 132,606	$ 1,083,023	$ (61,872)	$ 1,209,049
Common Stock Dividends			(48,000)		(48,000)
Preferred Stock Dividends			(121)		(121)
TOTAL					1,160,928
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $5,069				(9,414)	(9,414)
Minimum Pension Liability, Net of Tax of $0				(2,466)	(2,466)
NET INCOME			29,063		29,063
TOTAL COMPREHENSIVE INCOME					17,183
JUNE 30, 2004	$ 55,292	$ 132,606	$ 1,063,965	$ (73,752)	$ 1,178,111
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(121)		(121)
TOTAL					1,118,522
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $546				(1,014)	(1,014)
NET INCOME			29,505		29,505
TOTAL COMPREHENSIVE INCOME					28,491
JUNE 30, 2005	$ 55,292	$ 132,606	$ 964,288	$ (5,173)	$ 1,147,013

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Transmission	$ 809,467	$ 788,371
Distribution	1,452,625	1,433,380
General	230,953	220,435
Construction Work in Progress	55,690	50,612
Total	2,548,735	2,492,798
Accumulated Depreciation and Amortization	744,189	725,225
TOTAL - NET	1,804,546	1,767,573
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	2,273	1,577
Bond Defeasance Funds	21,811	22,110
TOTAL	24,084	23,687
CURRENT ASSETS		
Cash and Cash Equivalents	2,094	-
Other Cash Deposits	242,600	135,132
Accounts Receivable:		
Customers	153,737	157,431
Affiliated Companies	21,356	67,860
Accrued Unbilled Revenues	26,979	21,589
Allowance for Uncollectible Accounts	(994)	(3,493)
Materials and Supplies	12,861	12,288
Risk Management Assets	4,017	14,048
Margin Deposits	2,609	1,891
Prepayments and Other Current Assets	16,042	9,151
TOTAL	481,301	415,897
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	18,936	15,236
Wholesale Capacity Auction True-Up	585,336	559,973
Unamortized Loss on Reacquired Debt	11,311	11,842
Designated for Securitization	1,347,502	1,361,299
Deferred Debt - Restructuring	11,139	11,596
Other	90,302	102,032
Securitized Transition Assets	622,137	642,384
Long-term Risk Management Assets	4,983	9,508
Prepaid Pension Obligations	110,210	109,628

Deferred Property Taxes	15,450	-
Deferred Charges	34,660	36,986
TOTAL	2,851,966	2,860,484
Assets Held for Sale - Texas Generation Plants	45,611	628,149
TOTAL ASSETS	$ 5,207,508	$ 5,695,790

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $25 par value per share:		
Authorized - 12,000,000 shares		
Outstanding - 2,211,678 shares	$ 55,292	$ 55,292
Paid-in Capital	132,606	132,606
Retained Earnings	964,288	1,084,904
Accumulated Other Comprehensive Income (Loss)	(5,173)	(4,159)
Total Common Shareholder's Equity	1,147,013	1,268,643
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders' Equity	1,152,953	1,274,583
Long-term Debt - Nonaffiliated	1,672,748	1,541,552
TOTAL	2,825,701	2,816,135
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	237,262	365,742
Advances from Affiliates	120,064	207
Accounts Payable:		
General	51,779	109,688
Affiliated Companies	37,004	64,045
Customer Deposits	5,414	6,147
Taxes Accrued	113,542	184,014
Interest Accrued	38,672	41,227
Risk Management Liabilities	4,272	8,394
Obligations Under Capital Leases	423	412
Other	22,514	20,115
TOTAL	630,946	799,991
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,177,334	1,247,111
Long-term Risk Management Liabilities	2,670	4,896
Regulatory Liabilities:		
Asset Removal Costs	104,214	102,624
Deferred Investment Tax Credits	105,871	107,743
Over-recovery of Fuel Costs	209,126	211,526
Retail Clawback	61,384	61,384
Other	77,166	76,653
Obligations Under Capital Leases	496	468
Deferred Credits and Other	11,651	17,276
TOTAL	1,749,912	1,829,681

Liabilities Held for Sale - Texas Generation Plants	949	249,983
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,207,508	$ 5,695,790

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 29,505	$ 29,063
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	64,720	57,976
Accretion Expense	7,549	8,209
Deferred Income Taxes	(83,369)	(11,682)
Deferred Investment Tax Credits	(1,872)	(2,603)
Deferred Property Taxes	(15,450)	(22,440)
Pension and Postemployment Benefit Reserves	(1,516)	481
Mark-to-Market of Risk Management Contracts	7,085	4,593
Pension Contributions	(113)	(675)
Carrying Costs	(14,797)	-
Wholesale Capacity Auction True-up	769	-
Over/Under Fuel Recovery	(2,400)	60,000
(Gain)/Loss on Sale of Assets	16	(312)
Change in Other Noncurrent Assets	(6,169)	2,905
Change in Other Noncurrent Liabilities	3,176	(27,166)
Changes in Components of Working Capital:		
Accounts Receivable, Net	46,481	(26,582)
Fuel, Materials and Supplies	(969)	(3,735)
Accounts Payable	(62,628)	18,804
Taxes Accrued	(69,046)	31,378
Customer Deposits	(733)	4,361
Interest Accrued	(2,555)	(756)
Other Current Assets	(9,285)	(371)
Other Current Liabilities	1,822	(3,173)
Net Cash Flows From (Used For) Operating Activities	(109,779)	118,275
INVESTING ACTIVITIES		
Construction Expenditures	(61,408)	(49,339)
Proceeds From Sale of Assets	313,709	1,477
Change in Other Cash Deposits, Net	(107,468)	(93,607)
Change in Bond Defeasance Funds and Other	-	(21,670)
Net Cash Flows From (Used For) Investing Activities	144,833	(163,139)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	276,690	-
Retirement of Long-term Debt	(279,386)	(35,004)
Changes in Advances to/from Affiliates, Net	119,857	133,039
Dividends Paid on Common Stock	(150,000)	(48,000)

Dividends Paid on Cumulative Preferred Stock	(121)	(121)
Net Cash Flows From (Used For) Financing Activities	(32,960)	49,914
Net Increase in Cash and Cash Equivalents	2,094	5,050
Cash and Cash Equivalents at Beginning of Period	-	760
Cash and Cash Equivalents at End of Period	$ 2,094	$ 5,810

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $52,441,000 and $61,529,000 and for income taxes was $161,372,000 and $(7,067,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $261,000 and $218,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $1,697,000 and $(423,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

AEP TEXAS NORTH COMPANY

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

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income (in millions)

Second Quarter of 2004 Net Income		$ 8
Changes in Gross Margin:		
Texas Supply	4	
Wires Revenue	3	
Off-system Sales	(2)	
Transmission Revenue	1	
Total Change in Gross Margin		6
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(1)	
Total Change in Operating Expenses and Other:		(1)
Income Tax Expense		(1)
Second Quarter of 2005 Net Income		$ 12

Net income increased $4 million due mainly to increases in gross margin.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins increased by $4 million primarily due to a $3 million increase in capacity sales, offset by lower sales volumes of 18% due to the loss of Centrica, our largest REP customer. Also, provision for rate refunds decreased $13 million due to the 2004 final fuel reconciliation true-up, offset by a decrease of $13 million in the net fuel revenue/fuel expense.
- Wires Revenue increased by $3 million primarily due to an increase in delivery volumes of 10%.
- Margins from Off-system Sales decreased by $2 million primarily due to lower optimization activity.
- Transmission Revenue increased $1 million primarily due to Texas transmission rate increases.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $1 million primarily related to field data collection for tracking system upgrades, 2005 staffing and budget review severance and disposal of fuel oil inventory, reduced in part by lower power plant maintenance on Reliability Must Run (RMR) plants no longer in service.

Income Taxes

The effective tax rate for the second quarter of 2005 and 2004 was 25.0% and 32.6%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, federal income tax adjustments and state income taxes. The decrease in the effective tax rate for the comparative period is primarily due to federal income tax adjustments and state income taxes.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income
(in millions)

Six Months Ended June 30, 2004 Net Income		$ 21
Changes in Gross Margin:		
Wires Revenue	2	
Off-system Sales	(3)	
Transmission Revenue	2	
Other Revenue	(4)	
Total Change in Gross Margin		(3)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	1	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	(1)	
Nonoperating Income and Expenses, Net	(3)	
Interest Charges	2	
Total Change in Operating Expenses and Other:		(2)
Income Tax Expense		3
Six Months ended June 30, 2005 Net Income		$ 19

Net income decreased $2 million due mainly to decreases in gross margin.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Wires Revenue increased by $2 million primarily due to higher delivery volumes of 5%.
- Margins from Off-system Sales for 2005 decreased by $3 million primarily due to lower optimization activity.
- Transmission Revenue increased $2 million due primarily to Texas transmission rate increases.
- Other Revenue decreased $4 million primarily due to a prior year favorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data received for the years 2001 through 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $1 million primarily due to decreased maintenance for RMR plants no longer in service.
- Nonoperating Income and Expenses, Net increased $3 million primarily due to $5 million of income in 2004 relating to risk management contracts which expired in December 2004 offset by increased net revenue of $2 million from third party nonutility construction projects.
- Interest Charges decreased $2 million primarily due to long-term debt maturities in 2004 and interest in 2004 related to the FERC settlement with wholesale customers.

Income Taxes

The effective tax rate for the six months ended 2005 and 2004 was 28.6% and 33.7%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate for the comparative period is primarily due to state income taxes and changes in permanent differences.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements during the first six months of 2005.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end.

Significant Factors

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	4,192
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(1,608)
Fair Value of New Contracts When Entered During the Period (b)		32
Net Option Premiums Paid/(Received) (c)		(5)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(1,481)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		1,130
Net Cash Flow Hedge Contracts (f)		(241)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	889

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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, 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 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 Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheets

As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 1,727	$ 9	$ 1,736
Noncurrent Assets	2,151	3	2,154
Total MTM Derivative Contract Assets	3,878	12	3,890
Current Liabilities	(1,616)	(231)	(1,847)
Noncurrent Liabilities	(1,132)	(22)	(1,154)
Total MTM Derivative Contract Liabilities	(2,748)	(253)	(3,001)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,130	$ (241)	$ 889

(a) Does not include Cash Flow 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 Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (288)	$ (2)	$ 229	$ -	$ -	$ -	$ (61)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	617	782	258	280	-	-	1,937
Prices Based on Models and Other Valuation Methods (b)	(316)	(558)	(232)	(25)	176	209	(746)
Total	$ 13	$ 222	$ 255	$ 255	$ 176	$ 209	$ 1,130

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external

sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $125 thousand of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 285
Changes in Fair Value (a)	(319)
Reclassifications from AOCI to Net Income (b)	(120)
Ending Balance June 30, 2005	$ (154)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $142 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005	Twelve Months Ended December 31, 2004

(in thousands)				(in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$32	$38	$19	$11	$68	$221	$95	$33

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $10 million and $13 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	2004	2005	2004
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 97,330	$ 90,330	$ 169,273	$ 179,042
Sales to AEP Affiliates	12,880	12,027	24,170	26,745
TOTAL	110,210	102,357	193,443	205,787
OPERATING EXPENSES				
Fuel for Electric Generation	11,355	10,661	23,966	18,161
Fuel from Affiliates for Electric Generation	-	12,542	372	23,766
Purchased Electricity for Resale	37,604	23,282	53,942	41,305
Purchased Electricity from AEP Affiliates	-	544	22	4,076
Other Operation	22,404	20,918	40,965	41,299
Maintenance	4,920	5,950	9,139	10,633
Depreciation and Amortization	10,362	9,854	20,517	19,546
Taxes Other Than Income Taxes	5,713	5,293	11,418	10,397
Income Taxes	3,093	2,541	6,679	8,482
TOTAL	95,451	91,585	167,020	177,665
OPERATING INCOME	14,759	10,772	26,423	28,122
Nonoperating Income	5,213	15,632	41,215	29,388
Nonoperating Expenses	2,205	11,962	37,313	22,898
Nonoperating Income Tax Expense	894	1,209	1,074	2,103
Interest Charges	4,869	5,482	9,853	11,662
NET INCOME	12,004	7,751	19,398	20,847
Preferred Stock Dividend Requirements	26	26	52	52
EARNINGS APPLICABLE TO COMMON STOCK	$ 11,978	$ 7,725	$ 19,346	$ 20,795

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 137,214	$ 2,351	$ 125,428	$ (26,718)	$ 238,275
Common Stock Dividends			(2,000)		(2,000)
Preferred Stock Dividends			(52)		(52)
TOTAL					236,223
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,704				(3,164)	(3,164)
NET INCOME			20,847		20,847
TOTAL COMPREHENSIVE INCOME					17,683
JUNE 30, 2004	$ 137,214	$ 2,351	$ 144,223	$ (29,882)	$ 253,906
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421
Common Stock Dividends			(12,626)		(12,626)
Preferred Stock Dividends			(52)		(52)
TOTAL					297,743
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $236				(439)	(439)
NET INCOME			19,398		19,398
TOTAL COMPREHENSIVE INCOME					18,959
JUNE 30, 2005	$ 137,214	$ 2,351	$ 177,704	$ (567)	$ 316,702

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 288,325	$ 287,212
Transmission	283,435	281,359
Distribution	483,763	474,961
General	115,911	115,174
Construction Work in Progress	26,581	23,621
Total	1,198,015	1,182,327
Accumulated Depreciation and Amortization	414,781	405,933
TOTAL - NET	783,234	776,394
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	1,181	1,407
CURRENT ASSETS		
Cash and Cash Equivalents	938	-
Other Cash Deposits	2,308	2,308
Advances to Affiliates	63,665	51,504
Accounts Receivable:		
Customers	82,753	90,109
Affiliated Companies	14,591	21,474
Accrued Unbilled Revenues	4,816	3,789
Allowance for Uncollectible Accounts	(609)	(787)
Unbilled Construction Costs	6,320	22,065
Fuel Inventory	5,572	3,148
Materials and Supplies	8,344	8,273
Risk Management Assets	1,736	6,071
Margin Deposits	2,603	818
Prepayments and Other	917	1,053
TOTAL	193,954	209,825
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Deferred Debt - Restructuring	5,849	6,093
Unamortized Loss on Reacquired Debt	1,464	2,147
Other	3,484	3,783
Long-term Risk Management Assets	2,154	4,110
Prepaid Pension Obligations	44,909	44,911
Deferred Property Taxes	8,145	-
Other Deferred Charges	2,411	2,859

TOTAL	68,416	63,903
TOTAL ASSETS	$ 1,046,785	$ 1,051,529

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $25 par value per share:		
Authorized - 7,800,000 shares		
Outstanding - 5,488,560 shares	$ 137,214	$ 137,214
Paid-in Capital	2,351	2,351
Retained Earnings	177,704	170,984
Accumulated Other Comprehensive Income (Loss)	(567)	(128)
Total Common Shareholder's Equity	316,702	310,421
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,357	2,357
Total Shareholders' Equity	319,059	312,778
Long-term Debt - Nonaffiliated	276,797	276,748
TOTAL	595,856	589,526
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	37,609	37,609
Accounts Payable:		
General	42,876	22,444
Affiliated Companies	36,587	52,801
Customer Deposits	632	1,020
Taxes Accrued	25,422	37,269
Interest Accrued	5,045	5,044
Risk Management Liabilities	1,847	3,628
Obligations Under Capital Leases	212	220
Other	8,925	9,628
TOTAL	159,155	169,663
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	140,138	138,465
Long-term Risk Management Liabilities	1,154	2,116
Regulatory Liabilities:		
Asset Removal Costs	82,838	81,143
Deferred Investment Tax Credits	18,062	18,698
Over-recovery of Fuel Costs	4,716	3,920
Retail Clawback	13,924	13,924
Excess Earnings	13,022	13,270
SFAS 109 Regulatory Liability, Net	7,243	8,500
Other	1,059	1,319
Obligations Under Capital Leases	372	314
Deferred Credits and Other	9,246	10,671
TOTAL	291,774	292,340

Commitments and Contingencies (Note 5)				
TOTAL CAPITALIZATION AND LIABILITIES	$	1,046,785	$	1,051,529

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 19,398	$ 20,847
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	20,517	19,546
Deferred Income Taxes	(1,742)	(2,767)
Deferred Investment Tax Credits	(636)	(656)
Deferred Property Taxes	(8,145)	(7,400)
Mark-to-Market of Risk Management Contracts	3,062	1,955
Over/Under Fuel Recovery	796	13,500
Change in Other Noncurrent Assets	(2,432)	(6,449)
Change in Other Noncurrent Liabilities	1,924	3,289
Changes in Components of Working Capital:		
Accounts Receivable, Net	13,034	281
Fuel, Materials and Supplies	(2,495)	2,326
Accounts Payable	3,672	(2,590)
Taxes Accrued	(11,847)	14,527
Customer Deposits	(388)	837
Other Current Assets	15,059	(3,047)
Other Current Liabilities	(710)	(2,783)
Net Cash Flows From Operating Activities	49,067	51,416
INVESTING ACTIVITIES		
Construction Expenditures	(24,323)	(18,117)
Change in Other Cash Deposits, Net	-	564
Proceeds from Sale of Assets	1,033	-
Net Cash Flows Used For Investing Activities	(23,290)	(17,553)
FINANCING ACTIVITIES		
Retirement of Long-term Debt	-	(24,036)
Changes in Advances to/from Affiliates, Net	(12,161)	(6,391)
Dividends Paid on Common Stock	(12,626)	(2,000)
Dividends Paid on Cumulative Preferred Stock	(52)	(52)
Net Cash Flows Used For Financing Activities	(24,839)	(32,479)
Net Increase in Cash and Cash Equivalents	938	1,384
Cash and Cash Equivalents at Beginning of Period	-	2
Cash and Cash Equivalents at End of Period	$ 938	$ 1,386

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $9,014,000 and $11,139,000 and for income taxes was $21,865,000 and $(412,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $171,000 and $122,000, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $546,000 and $(285,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$ 22
Changes in Gross Margin:		
Retail Margins	(32)	
Off-system Sales	12	
Transmission Revenues	(5)	
Other Revenues	2	
Total Change in Gross Margin		(23)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	10	
Depreciation and Amortization	1	
Nonoperating Income and Expenses, Net	6	
Interest Charges	(1)	
Total Change in Operating Expenses and Other		16
Income Tax Expense		9
Second Quarter of 2005 Net Income		$ 24

Net Income increased by $2 million to $24 million in the second quarter of 2005 in comparison to the second quarter of 2004. The key drivers of the increase were a $16 million net decrease in Operating Expenses and Other and a $9 million decrease in Income Tax Expense partially offset by a $23 million decrease in gross margin.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $32 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak demand that was established in December 2004 resulting in a $19 million increase in capacity settlement payments under the Interconnection Agreement. In addition, there was a $9 million decrease in fuel margins resulting from higher fuel costs.
- Margins from Off-system Sales for 2005 increased by $12 million in comparison to 2004 primarily due to higher physical sales caused by our new peak demand as well as higher optimization activity.
- Transmission Revenues decreased $5 million primarily due to the elimination of $11 million of revenues related to through and out rates partially offset by an increase of $6 million in revenues due to replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $10 million primarily due to a decrease in storm restoration and a reduction in planned maintenance in comparison to 2004 at Amos, Clinch River and Glen Lyn plants partially offset by an increase in PJM scheduling fees and an increase in transmission expenses related to the AEP Transmission Equalization Agreement.
- Nonoperating Income and Expenses, Net increased $6 million primarily due to the accrual of carrying costs on deferred Virginia environmental and reliability charges.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were 27.9% and 46.0% 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to an investment tax credit adjustment in 2004 as a result of the Virginia SCC extending the regulatory transition period and a decrease in 2005 state income taxes as a result of recording the effects of Ohio House Bill 66, which phases-out the Ohio Franchise Tax. Participation in the system integration agreement subjects us to Ohio Franchise Tax.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income
(in millions)

Six Months Ended June 30, 2004 Net Income		$ 87
Changes in Gross Margin:		
Retail Margins	(65)	
Off-system Sales	31	
Transmission Revenues	(13)	
Other Revenues	3	
Total Change in Gross Margin		(44)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	2	
Depreciation and Amortization	(1)	
Nonoperating Income and Expenses, Net	2	
Total Change in Operating Expenses and Other		3
Income Tax Expense		25
Six Months Ended June 30, 2005 Net Income		$ 71

Net Income decreased by $16 million to $71 million in the six months ended June 30, 2005 in comparison to the six months ended June 30, 2004. The key drivers of the decrease were a $44 million decrease in gross margin partially offset by a $25 million decrease in income taxes.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $65 million in comparison to 2004 primarily due to our higher MLR share caused by the increase in our peak demand that was established in December 2004 resulting in a $34 million increase in capacity settlement payments under the Interconnection Agreement. In addition, there was a $26 million decrease in fuel margins resulting from higher fuel costs.

- Margins from Off-system Sales for 2005 increased by $31 million in comparison to 2004 primarily due to higher physical sales caused by our new peak demand as well as higher optimization activity.
- Transmission Revenues decreased $13 million primarily due to the elimination of $23 million of revenues related to through and out rates partially offset by an increase of $10 million due to replacement SECA rates.

Income Taxes

The effective tax rates for the six months ended June 2005 and 2004 were 32.2% and 40.2% 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to an investment tax credit adjustment in 2004 as a result of the Virginia SCC extending the regulatory transition period and a decrease in 2005 state income taxes as a result of recording the effects of Ohio House Bill 66, which phases-out the Ohio Franchise Tax. Participation in the system integration agreement subjects us to Ohio Franchise Tax.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the six months ended June 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 536	$ 4,561
Cash Flows From (Used For):		
Operating Activities	75,113	229,420
Investing Activities	(259,312)	(163,509)
Financing Activities	184,944	(66,841)
Net Increase (Decrease) in Cash and Cash Equivalents	745	(930)
Cash and Cash Equivalents at End of Period	$ 1,281	$ 3,631

Operating Activities

Our Net Cash Flows From Operating Activities were $75 million in 2005. We produced income of $71 million during the period and noncash expense items of $96 million for Depreciation and Amortization partially offset by Pension Contributions of $40 million. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items.

Our Net Cash Flows From Operating Activities were $229 million in 2004. We produced income of $87 million during the period and had a noncash expense item of $95 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital had no significant items.

Investing Activities

Net Cash Flows Used For Investing Activities during 2005 and 2004 primarily reflect our Construction Expenditures of $268 million and $205 million, respectively. Construction Expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. In 2005 and 2004, capital projects for transmission expenditures are primarily related to the Jacksons Ferry-Wyoming 765 kV transmission line. Environmental upgrades include the installation of selective catalytic reduction (SCR) equipment on Amos Unit 1 and the flue gas desulfurization project at the Mountaineer Plant. For the remainder of 2005, we expect our Construction Expenditures to be approximately $430 million.

Financing Activities

In 2005, we issued three Senior Unsecured Notes totaling $600 million with varying interest rates. We also issued Notes Payable - Affiliates of $100 million and received a capital contribution from our parent of $100 million. We retired $450 million of Senior Unsecured Notes with an interest rate of 4.80% and retired three First Mortgage Bonds totaling $125 million with varying interest rates. In addition, we repaid $34 million of Advances from Affiliates.

In 2004, we retired $45 million of First Mortgage Bonds and $40 million of Installment Purchase Contracts with an interest rate of 7.13% and 5.45%, respectively. In addition, we received $69 million of Advances from Affiliates and paid $50 million in Common Stock Dividends.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 250,000	5.00	2017
Senior Unsecured Notes	200,000	4.95	2015
Senior Unsecured Notes	150,000	4.40	2010
Notes Payable - Affiliated	100,000	4.708	2010

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 450,000	4.80	2005
First Mortgage Bonds	50,000	8.00	2005
First Mortgage Bonds	45,000	8.00	2025
First Mortgage Bonds	30,000	6.89	2005

Liquidity

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

Summary Obligation Information

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

Significant Factors

Virginia Environmental and Reliability Costs

In April 2004, the Virginia Electric Restructuring Act was amended to include a provision which permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, we filed a request with the Virginia State Corporation Commission (Virginia SCC) seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. Approximately $14 million of the amount requested represents incremental E&R costs for the twelve months ending June 30, 2005 and $48 million represents projected incremental E&R costs to be incurred for the twelve months ended June 30, 2006. The $62 million request relates to 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, recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kV transmission line construction and other incremental T&D system reliability costs.

We requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. If approved, the recovery factor will be applied as a 9.18% surcharge to customer bills. We proposed the difference between the actual incremental costs incurred and the cost recovered be subject to future rate adjustment.

On July 14, 2005, the Virginia SCC issued an order that established a procedural schedule in our filing including the convening of a public hearing on February 7, 2006. The order provided that no portion of our application should become effective pending further decision of the Virginia SCC. Each party to the proceeding may file legal arguments on or before September 6, 2005, on whether and, under what circumstances, the Virginia SCC has the authority to make effective, on an interim basis subject to refund, any portion of our requested rate change. We are unable to predict the final outcome of this proceeding. If the Virginia SCC denies recovery of net incremental amounts deferred, it would adversely affect future results of operations and cash flows.

West Virginia Rate Case

On July 1, 2005, WPCo and we formally notified the Public Service Commission of West Virginia of our intent to file a joint general rate case for increases in retail rates in the third quarter of 2005. The filing will include, among other things, a request to reinstate the suspended expanded fuel, net energy and purchased power clause and to provide for scheduled rate recovery of significant environmental and transmission expenditures. As of June 30, 2005 and December 31, 2004, we had $52 million of previously over-recovered fuel, net energy and purchased power costs recorded in Regulatory Liabilities - Over-recovery of Fuel Cost on our Condensed Consolidated Balance Sheets. We are unable to predict the ultimate effect of this filing on revenues, results of operations, cash flows and financial condition.

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	54,124
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(10,478)
Fair Value of New Contracts When Entered During the Period (b)		682
Net Option Premiums Paid/(Received) (c)		(294)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		15,177
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		3,593
Total MTM Risk Management Contract Net Assets		62,804
Net Cash Flow and Fair Value Hedge Contracts (f)		(9,301)
DETM Assignment (g)		(18,943)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	34,560

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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, 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 below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheets
As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 91,499	$ 486	$ -	$ 91,985
Noncurrent Assets	164,321	100	-	164,421
Total MTM Derivative Contract Assets	255,820	586	-	256,406
Current Liabilities	(84,208)	(8,578)	(6,373)	(99,159)
Noncurrent Liabilities	(108,808)	(1,309)	(12,570)	(122,687)
Total MTM Derivative Contract Liabilities	(193,016)	(9,887)	(18,943)	(221,846)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 62,804	$ (9,301)	$ (18,943)	$ 34,560

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (10,546)	$ (85)	$ 8,362	$ -	$ -	$ -	$ (2,269)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	22,863	32,936	11,448	11,743	-	-	78,990
Prices Based on Models and Other Valuation Methods (b)	(11,715)	(17,016)	(4,753)	1,575	9,970	8,022	(13,917)

Total	$ 602	$ 15,835	$15,057	$13,318	$ 9,970	$ 8,022	$ 62,804

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

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

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $8.5 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value Hedges.

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

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

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance December 31, 2004	$ 2,422	$ (176)	$ (11,570)	$ (9,324)
Changes in Fair Value (a)	(3,692)	-	(6,327)	(10,019)
Reclassifications from AOCI to Net Income (b)	(4,380)	2	515	(3,863)
Ending Balance June 30, 2005	$ (5,650)	$ (174)	$ (17,382)	$ (23,206)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

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

$7,533 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$1,162	$1,391	$679	$399	$577	$1,883	$812	$277

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $113 million and $99 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 439,548	$ 414,865	$ 943,689	$ 888,090
Sales to AEP Affiliates	55,979	51,047	108,917	104,929
TOTAL	495,527	465,912	1,052,606	993,019
OPERATING EXPENSES				
Fuel for Electric Generation	123,017	98,694	236,398	209,405
Purchased Electricity for Resale	26,732	17,786	54,965	34,430
Purchased Electricity from AEP Affiliates	107,023	87,793	233,986	178,280
Other Operation	77,284	72,058	148,292	140,800
Maintenance	37,266	52,933	84,456	94,253
Depreciation and Amortization	46,491	47,231	96,450	95,144
Taxes Other Than Income Taxes	23,322	23,499	47,361	46,952
Income Taxes	8,756	19,836	34,998	60,276
TOTAL	449,891	419,830	936,906	859,540
OPERATING INCOME	45,636	46,082	115,700	133,479
Nonoperating Income	8,768	3,152	12,255	8,699
Nonoperating Expenses	2,441	3,208	7,004	5,741
Nonoperating Income Tax Expense (Credit)	605	(1,263)	(1,278)	(1,625)
Interest Charges	27,145	25,463	51,344	50,900
NET INCOME	24,213	21,826	70,885	87,162
Preferred Stock Dividend Requirements, Including Capital Stock Expense and Other Expense	905	798	1,702	1,621
EARNINGS APPLICABLE TO COMMON STOCK	$ 23,308	$ 21,028	$ 69,183	$ 85,541

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 260,458	$ 719,899	$ 408,718	$ (52,088)	$1,336,987
Common Stock Dividends			(50,000)		(50,000)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense		1,221	(1,221)		-
TOTAL					1,286,587
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,402				(4,462)	(4,462)
NET INCOME			87,162		87,162
TOTAL COMPREHENSIVE INCOME					82,700
JUNE 30, 2004	$ 260,458	$ 721,120	$ 444,259	$ (56,550)	$1,369,287
DECEMBER 31, 2004	$ 260,458	$ 722,314	$ 508,618	$ (81,672)	$1,409,718
Capital Contribution from Parent		100,000			100,000
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense and Other		2,447	(1,302)		1,145
TOTAL					1,510,463
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,474				(13,882)	(13,882)
NET INCOME			70,885		70,885
TOTAL COMPREHENSIVE INCOME					57,003
JUNE 30, 2005	$ 260,458	$ 824,761	$ 577,801	$ (95,554)	$1,567,466

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 2,689,055	$ 2,502,273
Transmission	1,262,915	1,255,390
Distribution	2,104,939	2,070,377
General	294,275	302,474
Construction Work in Progress	390,272	399,116
Total	6,741,456	6,529,630
Accumulated Depreciation and Amortization	2,475,900	2,443,218
TOTAL - NET	4,265,556	4,086,412
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	20,743	20,378
Other Investments	12,951	18,775
TOTAL	33,694	39,153
CURRENT ASSETS		
Cash and Cash Equivalents	1,281	536
Other Cash Deposits	167	1,133
Accounts Receivable:		
Customers	149,541	126,422
Affiliated Companies	114,762	140,950
Accrued Unbilled Revenues	34,017	51,427
Miscellaneous	1,653	1,264
Allowance for Uncollectible Accounts	(2,181)	(5,561)
Risk Management Assets	91,985	81,811
Fuel	73,426	45,756
Materials and Supplies	43,849	45,644
Margin Deposits	13,227	8,329
Prepayments and Other	21,228	12,192
TOTAL	542,955	509,903
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	342,714	343,415
Transition Regulatory Assets	23,345	25,467
Unamortized Loss on Reacquired Debt	18,697	18,157
Other	62,316	36,368
Long-term Risk Management Assets	164,421	81,245
Emission Allowances	49,257	38,931

Deferred Property Taxes	31,746	37,071
Deferred Charges and Other	9,480	23,796
TOTAL	701,976	604,450
TOTAL ASSETS	$ 5,544,181	$ 5,239,918

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity		
Common Stock - No par value:		
Authorized - 30,000,000 shares		
Outstanding - 13,499,500 shares	$ 260,458	$ 260,458
Paid-in Capital	824,761	722,314
Retained Earnings	577,801	508,618
Accumulated Other Comprehensive Income (Loss)	(95,554)	(81,672)
Total Common Shareholder's Equity	1,567,466	1,409,718
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,784	17,784
Total Shareholders' Equity	1,585,250	1,427,502
Long-term Debt:		
Nonaffiliated	1,705,480	1,254,588
Affiliated	100,000	-
Total Long-term Debt	1,805,480	1,254,588
TOTAL	3,390,730	2,682,090
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	100,010	530,010
Advances from Affiliates	176,692	211,060
Accounts Payable:		
General	167,684	130,710
Affiliated Companies	74,517	76,314
Risk Management Liabilities	99,159	89,136
Taxes Accrued	60,557	90,404
Interest Accrued	23,817	21,076
Customer Deposits	58,269	42,822
Obligations Under Capital Leases	6,016	6,742
Other	51,015	56,645
TOTAL	817,736	1,254,919
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	862,567	852,536
Regulatory Liabilities:		
Asset Removal Costs	88,912	95,763
Over-recovery of Fuel Cost	52,041	57,843
Deferred Investment Tax Credits	28,114	30,382
Unrealized Gain on Forward Commitments	33,236	23,270
Employee Benefits and Pension Obligations	92,406	130,530
Long-term Risk Management Liabilities	122,687	57,349

Asset Retirement Obligations	25,576	24,626
Obligations Under Capital Leases	11,101	13,136
Deferred Credits	19,075	17,474
TOTAL	1,335,715	1,302,909
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,544,181	$ 5,239,918

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 70,885	$ 87,162
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	96,450	95,144
Accretion Expense	950	859
Deferred Income Taxes	18,206	24,377
Deferred Investment Tax Credits	(2,268)	2,090
Deferred Property Taxes	5,325	5,703
Pension Contributions	(39,875)	(348)
Pension and Postemployment Benefit Reserves	1,714	(3,041)
Mark-to-Market of Risk Management Contracts	(13,473)	5,615
Over/Under Fuel Recovery	(8,759)	607
Carrying Costs on Stranded Net Assets	(4,065)	-
Change in Other Noncurrent Assets	(11,945)	(11,419)
Change in Other Noncurrent Liabilities	(23,979)	9,559
Changes in Components of Working Capital:		
Accounts Receivable, Net	16,710	29,423
Fuel, Materials and Supplies	(25,875)	(21,872)
Accounts Payable	27,026	(32,223)
Taxes Accrued	(29,847)	27,674
Customer Deposits	15,447	11,623
Interest Accrued	2,741	36
Other Current Assets	(13,897)	6,425
Other Current Liabilities	(6,358)	(7,974)
Net Cash Flows From Operating Activities	75,113	229,420
INVESTING ACTIVITIES		
Construction Expenditures	(268,009)	(204,648)
Change in Other Cash Deposits, Net	966	40,615
Proceeds from Sale of Assets	7,731	524
Net Cash Flows Used For Investing Activities	(259,312)	(163,509)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	594,717	-
Issuance of Long-term Debt - Affiliated	100,000	-
Retirement of Long-term Debt	(575,005)	(85,005)
Capital Contribution from Parent	100,000	-
Changes in Advances to/from Affiliates, Net	(34,368)	68,564
Dividends Paid on Cumulative Preferred Stock	(400)	(400)

Dividends Paid on Common Stock	-	(50,000)
Net Cash Flows From (Used For) Financing Activities	184,944	(66,841)
Net Increase (Decrease) in Cash and Cash Equivalents	745	(930)
Cash and Cash Equivalents at Beginning of Period	536	4,561
Cash and Cash Equivalents at End of Period	$ 1,281	$ 3,631

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $45,064,000 and $46,739,000 and for income taxes was $47,461,000 and $3,946,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $748,000 and $910,000, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $8,151,000 and $(3,646,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$ 31
Changes in Gross Margin:		
Retail Margins	(5)	
Transmission Revenues	(5)	
Off-system Sales	4	
Other Revenues	1	
Total Change in Gross Margin		(5)
Changes in Operating Expenses and Other:		
Depreciation and Amortization	9	
Nonoperating Income and Expenses, Net	4	
Interest Charges	(1)	
Total Change in Operating Expenses and Other		12
Income Tax Expense		(3)
Second Quarter of 2005 Net Income		$ 35

Net Income increased $4 million to $35 million in 2005. The key drivers of the increase were a $9 million decrease in Depreciation and Amortization and a $4 million increase in Nonoperating Income and Expenses, Net partially offset by a $5 million decrease in gross margin.

The major components of our decrease in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins were $5 million less than the prior period primarily due to lower fuel margins partially offset by lower capacity settlement costs.
- Transmission Revenues decreased $5 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.
- Off-system Sales margins increased $4 million primarily due to favorable price margins.

Operating Expenses and Other changed between years as follows:

- Depreciation and Amortization expense decreased $9 million primarily due to the order in the rate stabilization plan which resulted in a reversal of unused shopping credits of $18 million partially offset by the establishment of a $7 million regulatory liability to benefit low income customers and for economic development.
- Nonoperating Income and Expenses, Net increased $4 million primarily due to the establishment of a regulatory

asset for carrying costs on environmental capital expenditures.

Income Tax

The effective tax rates for the second quarter of 2005 and 2004 were 35.0% and 33.6%, respectively. The difference in the 2004 effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, permanent differences, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income
(in millions)

Six Months Ended June 30, 2004 Net Income		$ 76
Changes in Gross Margin:		
Retail Margins	(11)	
Transmission Revenues	(11)	
Off-system Sales	6	
Other Revenues	(1)	
Total Change in Gross Margin		(17)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	11	
Depreciation and Amortization	8	
Taxes Other Than Income Taxes	(1)	
Nonoperating Income and Expenses, Net	6	
Interest Charges	(1)	
Total Change in Operating Expenses and Other		23
Income Tax Expense		-
Six Months Ended June 30, 2005 Net Income		$ 82

Net Income increased $6 million to $82 million in 2005. The increase is primarily due to an $11 million decrease in Other Operation and Maintenance expenses, an $8 million decrease in Depreciation and Amortization and a $6 million increase in Nonoperating Income and Expenses, Net partially offset by a decrease in gross margin of $17 million.

The major components of our decrease in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins were $11 million less than the prior period primarily due to lower fuel margins partially offset by lower capacity settlement costs.
- Transmission Revenues decreased $11 million primarily due to the loss of through and out rates, net of replacement SECA rates.
- Off-system Sales margins increased $6 million primarily due to favorable price margins.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $11 million primarily due to lower expenditures than estimated for storm expenses from the major ice storm in December 2004, a decrease in transmission expenses related to the AEP Transmission Equalization Agreement, and the settlement and cancellation of the corporate owned life insurance policy in February 2005.

- Depreciation and Amortization expense decreased $8 million primarily due to the order in the rate stabilization plan which resulted in a reversal of unused shopping credits of $18 million partially offset by the establishment of a $7 million regulatory liability to benefit low income customers and for economic development.
- Nonoperating Income and Expenses, Net increased $6 million primarily due to the establishment of a regulatory asset for carrying costs on environmental capital expenditures offset by lower margins on risk management activities.

Income Tax

The effective tax rates for the first six months of 2005 and 2004 were 33.2% and 35.1%, 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in permanent differences and state income taxes.

Financial Condition

Credit Ratings

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

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

Financing Activity

There were no long-term debt issuances or retirements during the first six months of 2005.

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end.

Significant Factors

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	30,919
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(7,395)
Fair Value of New Contracts When Entered During the Period (b)		599
Net Option Premiums Paid/(Received) (c)		(153)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		8,160
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		32,130
Net Cash Flow Hedge Contracts (f)		(4,502)
DETM Assignment (g)		(9,694)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	17,934

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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, 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 Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheets As of June 30, 2005 (in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 46,828	$ 177	$ -	$ 47,005
Noncurrent Assets	84,091	51	-	84,142
Total MTM Derivative Contract Assets	130,919	228	-	131,147
Current Liabilities	(43,099)	(4,322)	(3,261)	(50,682)
Noncurrent Liabilities	(55,690)	(408)	(6,433)	(62,531)
Total MTM Derivative Contract Liabilities	(98,789)	(4,730)	(9,694)	(113,213)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 32,130	$ (4,502)	$ (9,694)	$ 17,934

(a) Does not include Cash Flow Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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 Fair Value of Contracts as of June 30, 2005 (in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (5,397)	$ (44)	$ 4,279	$ -	$ -	$ -	$ (1,162)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	11,698	16,857	5,854	6,009	-	-	40,418
Prices Based on Models and Other Valuation Methods (b)	(5,991)	(8,712)	(2,436)	806	5,102	4,105	(7,126)

Total	$ 310	$ 8,101	$ 7,697	$ 6,815	$ 5,102	$ 4,105	$ 32,130

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $4.4 million of this mark-to-market value is in 2010.
(d) Amounts exclude Cash Flow Hedges.

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 1,393
Changes in Fair Value (a)	(2,044)
Reclassifications from AOCI to Net Income (b)	(2,241)
Ending Balance June 30, 2005	$ (2,892)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,659 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$595	$712	$347	$204	$332	$1,083	$467	$160

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $39 million and $48 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 339,969	$ 337,387	$ 680,125	$ 681,465
Sales to AEP Affiliates	20,918	21,333	45,011	39,952
TOTAL	360,887	358,720	725,136	721,417
OPERATING EXPENSES				
Fuel for Electric Generation	46,558	51,159	107,910	92,796
Fuel from Affiliates for Electric Generation	-	1,755	-	10,603
Purchased Electricity for Resale	8,703	4,769	17,906	9,450
Purchased Electricity from AEP Affiliates	95,172	85,706	174,947	167,421
Other Operation	58,302	59,390	107,070	117,263
Maintenance	26,700	25,944	42,084	42,770
Depreciation and Amortization	27,333	36,445	65,531	73,263
Taxes Other Than Income Taxes	32,913	32,726	69,075	68,052
Income Taxes	18,047	16,197	38,469	40,662
TOTAL	313,728	314,091	622,992	622,280
OPERATING INCOME	47,159	44,629	102,144	99,137
Nonoperating Income	578	650	5,788	5,617
Carrying Costs Income	4,158	120	6,916	231
Nonoperating Expenses	986	859	1,742	1,593
Nonoperating Income Tax Expense (Credit)	590	(628)	2,407	291
Interest Charges	15,668	14,413	28,580	27,227
NET INCOME	34,651	30,755	82,119	75,874
Preferred Stock Dividend Requirements including Capital Stock Expense and Other Expense	1,858	254	2,112	508
EARNINGS APPLICABLE TO COMMON STOCK	$ 32,793	$ 30,501	$ 80,007	$ 75,366

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 41,026	$ 576,400	$ 326,782	$ (46,327)	$ 897,881
Common Stock Dividends			(62,500)		(62,500)
Capital Stock Expense		508	(508)		-
TOTAL					835,381
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,290				(2,397)	(2,397)
NET INCOME			75,874		75,874
TOTAL COMPREHENSIVE INCOME					73,477
JUNE 30, 2004	$ 41,026	$ 576,908	$ 339,648	$ (48,724)	$ 908,858
DECEMBER 31, 2004	$ 41,026	$ 577,415	$ 341,025	$ (60,816)	$ 898,650
Common Stock Dividends			(57,000)		(57,000)
Capital Stock Expense and Other		2,112	(2,112)		-
TOTAL					841,650
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,307				(4,285)	(4,285)
NET INCOME			82,119		82,119
TOTAL COMPREHENSIVE INCOME					77,834
JUNE 30, 2005	$ 41,026	$ 579,527	$ 364,032	$ (65,101)	$ 919,484

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,716,269	$ 1,658,552
Transmission	444,161	432,714
Distribution	1,323,790	1,300,252
General	164,354	167,985
Construction Work in Progress	102,952	131,743
Total	3,751,526	3,691,246
Accumulated Depreciation and Amortization	1,510,315	1,471,950
TOTAL - NET	2,241,211	2,219,296
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	21,817	22,322
Other Investments	4,105	5,147
TOTAL	25,922	27,469
CURRENT ASSETS		
Cash and Cash Equivalents	694	25
Other Cash Deposits	-	33
Advances to Affiliates	62,172	141,550
Accounts Receivable:		
Customers	42,718	41,130
Affiliated Companies	57,540	72,854
Accrued Unbilled Revenues	11,527	19,580
Miscellaneous	1,117	1,145
Allowance for Uncollectible Accounts	(555)	(674)
Fuel	35,671	34,026
Materials and Supplies	33,835	37,137
Risk Management Assets	47,005	46,631
Margin Deposits	6,769	4,848
Prepayments and Other	16,234	11,499
TOTAL	314,727	409,784
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	17,591	16,481
Transition Regulatory Assets	159,269	156,676
Unamortized Loss on Reacquired Debt	12,772	13,155
Other	47,414	25,691
Long-term Risk Management Assets	84,142	46,735

Deferred Property Taxes	32,544	64,754
Deferred Charges and Other	47,762	49,855
TOTAL	401,494	373,347
TOTAL ASSETS	$ 2,983,354	$ 3,029,896

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - No par value:		
Authorized - 24,000,000 shares		
Outstanding - 16,410,426 shares	$ 41,026	$ 41,026
Paid-in Capital	579,527	577,415
Retained Earnings	364,032	341,025
Accumulated Other Comprehensive Income (Loss)	(65,101)	(60,816)
Total Common Shareholder's Equity	919,484	898,650
Preferred Stock - No Shares Outstanding	-	-
Authorized - 2,500,000 shares at $100 par value		
Authorized - 7,000,000 shares at $25 par value		
Total Shareholder's Equity	919,484	898,650
Long-term Debt:		
Nonaffiliated	851,757	851,626
Affiliated	100,000	100,000
Total Long-term Debt	951,757	951,626
TOTAL	1,871,241	1,850,276
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	36,000	36,000
Accounts Payable:		
General	51,674	63,606
Affiliated Companies	54,920	45,745
Customer Deposits	32,508	24,890
Taxes Accrued	102,195	195,284
Interest Accrued	16,615	16,320
Risk Management Liabilities	50,682	42,172
Obligations Under Capital Leases	3,402	3,854
Other	25,451	24,338
TOTAL	373,447	452,209
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	446,650	464,545
Regulatory Liabilities:		
Asset Removal Costs	106,850	103,104
Deferred Investment Tax Credits	26,612	27,933
Other	22,104	-
Employee Benefits and Pension Obligations	37,813	62,778
Long-term Risk Management Liabilities	62,531	32,731

Obligations Under Capital Leases	7,488	8,660
Asset Retirement Obligations	12,006	11,585
Deferred Credits and Other	16,612	16,075
TOTAL	738,666	727,411
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,983,354	$ 3,029,896

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 82,119	$ 75,874
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	65,531	73,263
Deferred Income Taxes	(1,593)	8,642
Deferred Investment Tax Credits	(1,321)	(1,473)
Pension and Postemployment Benefit Reserves	257	(2,674)
Deferred Property Taxes	32,210	30,763
Mark-to-Market of Risk Management Contracts	(5,171)	1,611
Carrying Costs Income	(6,916)	(231)
Pension Contributions	(25,222)	(8)
Gain on Sale of Assets	(1,352)	(1,786)
Change in Other Noncurrent Assets	(19,416)	(19,464)
Change in Other Noncurrent Liabilities	3,536	(809)
Changes in Components of Working Capital:		
Accounts Receivable, Net	21,688	20,483
Fuel, Materials and Supplies	1,657	(13,704)
Accounts Payable	(2,180)	(20,128)
Taxes Accrued	(93,089)	(18,790)
Customer Deposits	7,618	6,745
Interest Accrued	295	5
Other Current Assets	(6,656)	3,230
Other Current Liabilities	661	(2,894)
Net Cash Flows From Operating Activities	52,656	138,655
INVESTING ACTIVITIES		
Construction Expenditures	(78,061)	(66,693)
Change in Other Cash Deposits, Net	33	18
Proceeds from Sale of Assets	3,663	2,244
Net Cash Flows Used For Investing Activities	(74,365)	(64,431)
FINANCING ACTIVITIES		
Changes in Advances to/from Affiliates, Net	79,378	(558)
Dividends Paid on Common Stock	(57,000)	(62,500)
Issuance of Long-term Debt	-	43,095
Retirement of Long-term Debt	-	(54,695)
Net Cash Flows From (Used For) Financing Activities	22,378	(74,658)
Net Increase (Decrease) in Cash and Cash Equivalents	669	(434)

Cash and Cash Equivalents at Beginning of Period		25		3,377
Cash and Cash Equivalents at End of Period	$	694	$	2,943

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $27,390,000 and $25,131,000 and for income taxes was $78,019,000 and $(3,747,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $343,000 and $162,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(577,000) and $44,000 in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$	27
Changes in Gross Margin:			
Retail Margins	11		
Transmission Revenues	(5)		
Total Change in Gross Margin			6
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	4		
Interest Charges	2		
Total Change in Operating Expenses and Other			6
Income Tax Expense			(3)
Second Quarter of 2005 Net Income		$	36

Net Income increased $9 million to $36 million in the second quarter of 2005. The key drivers of the increase were a $6 million increase in gross margin and a $4 million decrease in Other Operation and Maintenance expenses.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins increased $11 million primarily due to an increase in capacity settlement payments received under the Interconnection Agreement related to the increase in an affiliate's peak.
- Transmission Revenues decreased $5 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $4 million primarily due to lower distribution maintenance expense reflecting the effect of 2004 storm damage.
- Interest Charges decreased $2 million primarily due to lower long-term debt outstanding and lower interest rates.

Income Tax

The effective tax rates for the second quarter of 2005 and 2004 were 34.8% and 36.7%, 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state and local income taxes.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income (in millions)

Six Months Ended June 30, 2004 Net Income		$ 70
Changes in Gross Margin:		
Retail Margins	16	
Transmission Revenues	(12)	
Off-system Sales and Other Revenues	3	
Total Change in Gross Margin		7
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(3)	
Taxes Other Than Income Taxes	(2)	
Nonoperating Income and Expenses, Net	(4)	
Interest Charges	4	
Total Change in Operating Expenses and Other		(5)
Income Tax Expense		3
Six Months Ended June 30, 2005 Net Income		$ 75

Net Income increased $5 million to $75 million in the first six months of 2005. The key driver of the increase was a $7 million increase in gross margin.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins increased $16 million primarily due to a $21 million increase in capacity settlement payments received under the Interconnection Agreement related to the increase in an affiliate's peak partially offset by an increase in unrecovered fuel costs due to fuel caps in our Indiana jurisdiction.
- Transmission Revenues decreased $12 million primarily due to the loss of through and out rates, net of replacement SECA rates.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $3 million primarily due to a $6 million increase in distribution maintenance mainly for January 2005 storm damage expenses and $4 million of accruals for employee severance costs partially offset by the settlement and cancellation of COLI policies in February 2005.
- Taxes Other Than Income Taxes increased $2 million primarily due to a $1 million increase in property taxes and a $1 million increase in payroll-related taxes.
- Nonoperating Income and Expenses, Net declined $4 million reflecting lower margins on risk management transactions.
- Interest Charges decreased $4 million primarily due to lower long-term debt outstanding and lower interest rates.

Income Tax

The effective tax rates for the first six months of 2005 and 2004 were 33.9% and 37.3%, 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower state and local income taxes and changes in permanent differences including COLI.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the first six months of 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 465	$ 3,899
Cash Flows From (Used For):		
Operating Activities	67,046	266,994
Investing Activities	(111,578)	(84,403)
Financing Activities	44,605	(183,319)
Net Increase (Decrease) in Cash and Cash Equivalents	73	(728)
Cash and Cash Equivalents at End of Period	$ 538	$ 3,171

Operating Activities

Our Net Cash Flows From Operating Activities were $67 million for the first six months of 2005. We produced Net Income of $75 million during the period including noncash expense items of $109 million for depreciation, amortization and accretion. 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 were contributions of $31 million to our pension trust, $99 million of federal income tax payments, partially offset by a net change in accounts receivable and payable of $15 million. Our affiliates paid receivables related to emission allowances during the first half of 2005.

Our Net Cash Flows From Operating Activities were $267 million in 2004. We produced Net Income of $70 million during the period and noncash expense items of $105 million for depreciation, amortization and accretion. The other changes in assets and liabilities represent items that had a cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items; the most significant relates to Taxes Accrued. During 2004, we did not make any federal income tax payments for our 2004 federal income tax liability since the AEP Consolidated tax group was not required to make any 2004 quarterly estimated federal income tax payments.

Investing Activities

Net Cash Flows Used For Investing Activities during 2005 were $112 million due to Construction Expenditures.

Construction Expenditures were primarily for nuclear generation, transmission and distribution assets to upgrade or replace equipment and improve reliability. For the remainder of 2005, we expect our construction expenditures to be approximately $200 million.

Our Net Cash Flows Used For Investing Activities were $84 million in 2004 for Construction Expenditures.

Financing Activities

During the first six months of 2005, we used cash of $61 million to retire preferred stock and $42 million to pay common dividends. These activities and our Construction Expenditures were supported by additional borrowing from the Utility Money Pool of $148 million. There were no long-term debt issuances or retirements during the first six months of 2005.

Our Net Cash Flows Used For Financing Activities were $183 million in 2004. We used cash from operations to repay short-term debt, retire long-term debt and pay common dividends.

Liquidity

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

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 are entered in the normal course of business. Our off-balance sheet arrangements have not changed significantly since year-end. For complete information on our off-balance sheet arrangements see “Off-balance Sheet Arrangements” in “Management’s Financial Discussion and Analysis” section of our 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 $61 million retirement of preferred stock.

Significant Factors

I&M Indiana Settlement Agreement

In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005 and filed the agreement with the IURC on March 14, 2005. The IURC approved the agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, we began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor will be adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), the ratio of the sum of fuel and one half maintenance expenses incurred by the pool members to the total kilowatt-hours of net generation, excluding us, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total actual fuel costs (except during a Cook Plant outage of greater than 60 days) are under the cap prices, the excess will be credited to customers over the next two fuel adjustment clause filings. Under the settlement, fuel costs in excess of the cap price cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, we will receive credit for 30% of the savings produced by that performance.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond our control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

Our cumulative under recovery for March 2004 through June 2005 recorded as fuel expense is $7 million. If future fuel cost per KWH through June 30, 2007 continue to exceed the caps, or if the base rate cap precludes us from seeking timely rate increases to recover increases in its cost of service through June 30, 2007, our future results of operations and cash flows would be adversely affected.

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section additional discussion of factors relevant to us.

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	34,573
(Gain) Loss from Contracts Realized/Settled During the Period (a)		62
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		(221)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		263
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		1,067
Total MTM Risk Management Contract Net Assets		35,744
Net Cash Flow and Fair Value Hedge Contracts (f)		(5,740)
DETM Assignment (g)		(10,839)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	19,165

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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, 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 below in Accumulated Other Comprehensive Income (Loss).

(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheets
As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 52,473	$ 197	$ -	$ 52,670
Noncurrent Assets	94,069	57	-	94,126
Total MTM Derivative Contract Assets	146,542	254	-	146,796
Current Liabilities	(48,293)	(5,378)	(3,646)	(57,317)
Noncurrent Liabilities	(62,505)	(616)	(7,193)	(70,314)
Total MTM Derivative Contract Liabilities	(110,798)	(5,994)	(10,839)	(127,631)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 35,744	$ (5,740)	$ (10,839)	$ 19,165

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (6,034)	$ (49)	$ 4,785	$ -	$ -	$ -	$ (1,298)
Prices Provided by Other External Sources - OTC							
Broker Quotes (a)	13,069	18,926	6,445	6,719	-	-	45,159
Prices Based on Models and Other Valuation							

Methods (b)	(6,707)	(9,820)	(2,787)	902	5,705	4,590	(8,117)
Total	$ 328	$ 9,057	$ 8,443	$ 7,621	$ 5,705	$ 4,590	$ 35,744

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

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

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $4.9 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value Hedges.

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

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power	**Interest Rate**	**Total**
Beginning Balance December 31, 2004	$ 1,558	$ (5,634)	$ (4,076)
Changes in Fair Value (a)	(2,285)	(186)	(2,471)
Reclassifications from AOCI to Net Income (b)	(2,506)	285	(2,221)
Ending Balance June 30, 2005	$ (3,233)	$ (5,535)	$ (8,768)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,558 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$665	$796	$388	$228	$371	$1,211	$522	$178

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $44 million and $53 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 357,500	$ 340,766	$ 719,092	$ 694,588
Sales to AEP Affiliates	79,858	65,025	160,409	122,670
TOTAL	437,358	405,791	879,501	817,258
OPERATING EXPENSES				
Fuel for Electric Generation	78,342	65,582	156,166	129,623
Purchased Electricity for Resale	12,730	6,191	24,002	12,554
Purchased Electricity from AEP Affiliates	71,984	65,665	145,993	128,793
Other Operation	100,026	106,116	191,002	206,966
Maintenance	48,366	46,276	102,688	84,318
Depreciation and Amortization	42,224	42,696	84,969	85,411
Taxes Other Than Income Taxes	15,110	15,472	32,617	30,688
Income Taxes	18,326	14,798	38,260	39,097
TOTAL	387,108	362,796	775,697	717,450
OPERATING INCOME	50,250	42,995	103,804	99,808
Nonoperating Income	21,709	19,866	39,206	40,454
Nonoperating Expenses	19,238	17,176	35,251	32,027
Nonoperating Income Tax Expense	650	878	413	2,491
Interest Charges	16,478	17,777	32,084	35,706
NET INCOME	35,593	27,030	75,262	70,038
Preferred Stock Dividend Requirements including Capital Stock Expense	107	119	225	237
EARNINGS APPLICABLE TO COMMON STOCK	$ 35,486	$ 26,911	$ 75,037	$ 69,801

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 56,584	$ 858,694	$ 187,875	$ (25,106)	$1,078,047
Common Stock Dividends			(59,293)		(59,293)
Preferred Stock Dividends			(169)		(169)
Capital Stock Expense		67	(67)		-
TOTAL					1,018,585
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,603				(2,978)	(2,978)
NET INCOME			70,038		70,038
TOTAL COMPREHENSIVE INCOME					67,060
JUNE 30, 2004	$ 56,584	$ 858,761	$ 198,384	$ (28,084)	$1,085,645
DECEMBER 31, 2004	$ 56,584	$ 858,835	$ 221,330	$ (45,251)	$1,091,498
Common Stock Dividends			(42,000)		(42,000)
Preferred Stock Dividends			(169)		(169)
Capital Stock Expense and Other		2,455	(56)		2,399
TOTAL					1,051,728
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,527				(4,692)	(4,692)
NET INCOME			75,262		75,262
TOTAL COMPREHENSIVE INCOME					70,570
JUNE 30, 2005	$ 56,584	$ 861,290	$ 254,367	$ (49,943)	$1,122,298

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 3,133,714	$ 3,122,883
Transmission	1,012,817	1,009,551
Distribution	1,012,925	990,826
General (including nuclear fuel)	273,264	275,622
Construction Work in Progress	215,354	163,515
Total	5,648,074	5,562,397
Accumulated Depreciation and Amortization	2,663,174	2,603,479
TOTAL - NET	2,984,900	2,958,918
OTHER PROPERTY AND INVESTMENTS		
Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds	1,095,165	1,053,439
Nonutility Property, Net	49,375	50,440
Other Investments	13,245	21,848
TOTAL	1,157,785	1,125,727
CURRENT ASSETS		
Cash and Cash Equivalents	538	465
Other Cash Deposits	-	46
Advances to Affiliates	-	5,093
Accounts Receivable:		
Customers	61,968	62,608
Affiliated Companies	100,326	124,134
Miscellaneous	3,557	4,339
Allowance for Uncollectible Accounts	(15)	(187)
Fuel	25,667	27,218
Materials and Supplies	104,332	103,342
Risk Management Assets	52,670	52,141
Margin Deposits	7,569	5,400
Prepayments and Other	15,428	10,541
TOTAL	372,040	395,140
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	136,468	147,167
Incremental Nuclear Refueling Outage Expenses, Net	45,002	44,244
Unamortized Loss on Reacquired Debt	22,712	21,039
DOE Decontamination Fund	11,640	14,215
Other	48,440	31,015

Long-term Risk Management Assets	94,126	52,256
Emission Allowances	31,301	27,093
Deferred Property Taxes	22,009	22,372
Deferred Charges and Other Assets	16,816	28,955
TOTAL	428,514	388,356
TOTAL ASSETS	$ 4,943,239	$ 4,868,141

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - No Par Value:		
Authorized - 2,500,000 Shares		
Outstanding - 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	861,290	858,835
Retained Earnings	254,367	221,330
Accumulated Other Comprehensive Income (Loss)	(49,943)	(45,251)
Total Common Shareholder's Equity	1,122,298	1,091,498
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,084	8,084
Total Shareholders' Equity	1,130,382	1,099,582
Long-term Debt	1,315,927	1,312,843
TOTAL	2,446,309	2,412,425
CURRENT LIABILITIES		
Cumulative Preferred Stock Due Within One Year	-	61,445
Advances from Affiliates	143,126	-
Accounts Payable:		
General	83,109	91,472
Affiliated Companies	45,996	51,066
Customer Deposits	35,079	29,366
Taxes Accrued	54,263	123,159
Interest Accrued	13,152	12,465
Risk Management Liabilities	57,317	47,174
Obligations Under Capital Leases	6,009	6,124
Other	57,067	70,237
TOTAL	495,118	492,508
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	306,028	315,730
Regulatory Liabilities:		
Asset Removal Costs	287,280	280,054
Deferred Investment Tax Credits	79,138	82,802
Excess ARO for Nuclear Decommissioning	259,103	245,175
Unrealized Gain on Forward Commitments	45,611	35,534
Other	33,097	33,695
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	64,618	66,472
Long-term Risk Management Liabilities	70,314	36,815
Obligations Under Capital Leases	38,544	44,608
Asset Retirement Obligations	735,401	711,769

Employee Benefits and Pension Obligations	43,694	70,027
Deferred Credits and Other	38,984	40,527
TOTAL	2,001,812	1,963,208
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 4,943,239	$ 4,868,141

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 75,262	$ 70,038
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	84,969	85,411
Accretion Expense	23,632	19,567
Amortization, net of Deferrals of Incremental Nuclear Refueling Outage Expenses	(758)	26,004
Deferred Income Taxes	3,476	(524)
Deferred Investment Tax Credits	(3,664)	(3,664)
Pension Contributions	(30,701)	(972)
Mark-to-Market of Risk Management Contracts	(5,598)	1,461
Change in Other Noncurrent Assets	(246)	(1,933)
Change in Other Noncurrent Liabilities	(11,947)	490
Changes in Components of Working Capital:		
Accounts Receivable, Net	25,058	42,682
Fuel, Materials and Supplies	561	(9,463)
Accounts Payable	(10,161)	(22,740)
Taxes Accrued	(68,896)	44,323
Customer Deposits	5,713	8,911
Other Current Assets	(7,056)	5,542
Other Current Liabilities	(12,598)	1,861
Net Cash Flows From Operating Activities	67,046	266,994
INVESTING ACTIVITIES		
Construction Expenditures	(121,092)	(84,363)
Change in Other Cash Deposits, Net	46	(40)
Proceeds from Sale of Assets	9,468	-
Net Cash Flows Used For Investing Activities	(111,578)	(84,403)
FINANCING ACTIVITIES		
Retirement of Cumulative Preferred Stock	(61,445)	(2,000)
Retirement of Long-term Debt	-	(55,000)
Changes in Advances to/from Affiliates, Net	148,219	(66,857)
Dividends Paid on Common Stock	(42,000)	(59,293)
Dividends Paid on Cumulative Preferred Stock	(169)	(169)
Net Cash Flows From (Used For) Financing Activities	44,605	(183,319)
Net Increase (Decrease) in Cash and Cash Equivalents	73	(728)
Cash and Cash Equivalents at Beginning of Period	465	3,899

Cash and Cash Equivalents at End of Period	$ 538	$ 3,171

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $29,427,000 and $34,825,000 and for income taxes was $106,891,000 and $189,000 in 2005 and 2004, respectively. Noncash acquisitions under capital leases were $652,000 and $1,165,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(3,272,000) and $(9,365,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$ 4
Changes in Gross Margin:		
Retail Margins	(7)	
Off-system Sales	3	
Transmission Revenues	(1)	
Other Revenues	2	
Total Change in Gross Margin		(3)
Total Change in Operating Expenses and Other		-
Income Tax Expense		1
Second Quarter of 2005 Net Income		$ 2

Net Income decreased by $2 million to $2 million in the second quarter of 2005 in comparison to the second quarter of 2004. The key driver of the decrease was a $3 million decrease in gross margin partially offset by a $1 million decrease in Income Tax Expense.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $7 million in comparison to 2004 primarily due to a $5 million increase in capacity settlement payments under the Interconnection Agreement resulting from our higher MLR share caused by the increase in our peak demand established in January 2005.
- Margins from Off-system Sales for 2005 increased by $3 million in comparison to 2004 primarily due to higher physical sales as well as higher optimization activity.
- Transmission Revenues decreased $1 million primarily due to the elimination of revenues related to through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" additional discussion of these FERC rate changes.
- Other Revenues increased $2 million primarily due to a gain on sales of emission allowances.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were 15.1% and 21.7%, 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to lower pretax income.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income
(in millions)

Six Months Ended June 30, 2004 Net Income		$ 16
Changes in Gross Margin:		
Retail Margins	(11)	
Off-system Sales	7	
Transmission Revenues	(3)	
Total Change in Gross Margin		(7)
Total Change in Operating Expenses and Other		-
Income Tax Expense		3
Six Months Ended June 30, 2005 Net Income		$ 12

Net Income decreased by $4 million to $12 million in the six months ended June 30, 2005 in comparison to the six months ended June 30, 2004. The key driver of the decrease was a $7 million decrease in gross margin partially offset by a $3 million decrease in Income Tax Expense.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $11 million in comparison to 2004 primarily due to a $9 million increase in capacity settlement payments under the Interconnection Agreement resulting from our higher MLR share caused by the increase in our peak demand established in both December 2004 and January 2005.
- Margins from Off-system Sales for 2005 increased by $7 million in comparison to 2004 primarily due to higher physical sales as well as higher optimization activity.
- Transmission Revenues decreased $3 million primarily due to the elimination of revenues related to through and out rates, net of replacement SECA rates.

Income Taxes

The effective tax rates for the six months ended June 2005 and 2004 were 26.7% and 32.2%, 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, amortization of investment tax credits and state income taxes.

Financial Condition

Credit Ratings

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

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

Financing Activity

Long-term debt issuances and retirements during the first six months of 2005 were:

Issuances

None

Retirements

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable-Affiliated	$20,000	6.501	2006

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end other than the $20 million retirement of Notes Payable-Affiliated.

Significant Factors

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 12,691
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(26)
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(67)
Change in Fair Value Due to Valuation Methodology Changes	-
Changes in Fair Value of Risk Management Contracts (d)	487
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	1,875
Total MTM Risk Management Contract Net Assets	14,960
Net Cash Flow and Fair Value Hedge Contracts (f)	(2,120)
DETM Assignment (g)	(4,509)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$ 8,331

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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 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 below in Accumulated Other Comprehensive Income (Loss).

(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to

Condensed Balance Sheets
As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 21,769	$ 211	$ -	$ 21,980
Noncurrent Assets	39,105	24	-	39,129
Total MTM Derivative Contract Assets	60,874	235	-	61,109
Current Liabilities	(20,035)	(2,010)	(1,517)	(23,562)
Noncurrent Liabilities	(25,879)	(345)	(2,992)	(29,216)
Total MTM Derivative Contract Liabilities	(45,914)	(2,355)	(4,509)	(52,778)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 14,960	$ (2,120)	$ (4,509)	$ 8,331

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) 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 Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (2,510)	$ (20)	$ 1,990	$ -	$ -	$ -	$ (540)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	5,442	7,832	2,733	2,794	-	-	18,801
Prices Based on Models and Other Valuation Methods (b)	(2,785)	(4,045)	(1,127)	375	2,372	1,909	(3,301)
Total	$ 147	$ 3,767	$ 3,596	$ 3,169	$ 2,372	$ 1,909	$ 14,960

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $2.0 million of this mark-to-market value is in 2010.
(d) Amounts exclude Cash Flow and Fair Value Hedges.

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

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 569	$ 244	$ 813
Changes in Fair Value (a)	(876)	-	(876)
Reclassifications from AOCI to Net Income (b)	(1,037)	(43)	(1,080)
Ending Balance June 30, 2005	$ (1,344)	$ 201	$ (1,143)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,151 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$277	$331	$162	$95	$135	$442	$191	$65

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $13 million and $16 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 109,294	$ 94,380	$ 224,954	$ 201,426
Sales to AEP Affiliates	13,007	12,373	25,196	18,985
TOTAL	122,301	106,753	250,150	220,411
OPERATING EXPENSES				
Fuel for Electric Generation	30,692	25,224	58,584	46,118
Purchased Electricity for Resale	44,796	31,817	89,659	65,123
Other Operation	15,417	13,499	29,977	26,771
Maintenance	8,482	10,214	14,398	17,539
Depreciation and Amortization	11,225	10,905	22,377	21,764
Taxes Other Than Income Taxes	2,219	2,395	4,644	4,723
Income Taxes	279	1,094	4,287	7,554
TOTAL	113,110	95,148	223,926	189,592
OPERATING INCOME	9,191	11,605	26,224	30,819
Nonoperating Income	621	482	1,066	1,434
Nonoperating Expenses	141	274	312	1,587
Nonoperating Income Tax Expense (Credit)	157	33	209	(94)
Interest Charges	7,068	7,712	14,438	15,081
NET INCOME	$ 2,446	$ 4,068	$ 12,331	$ 15,679

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 50,450	$ 208,750	$ 64,151	$ (6,213)	$ 317,138
Common Stock Dividends			(12,500)		(12,500)
TOTAL					304,638
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $518				(962)	(962)
NET INCOME			15,679		15,679
TOTAL COMPREHENSIVE INCOME					14,717
JUNE 30, 2004	$ 50,450	$ 208,750	$ 67,330	$ (7,175)	$ 319,355
DECEMBER 31, 2004	$ 50,450	$ 208,750	$ 70,555	$ (8,775)	$ 320,980
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,053				(1,956)	(1,956)
NET INCOME			12,331		12,331
TOTAL COMPREHENSIVE INCOME					10,375
JUNE 30, 2005	$ 50,450	$ 208,750	$ 82,886	$ (10,731)	$ 331,355

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 466,370	$ 462,641
Transmission	387,910	385,667
Distribution	446,449	438,766
General	59,475	57,929
Construction Work in Progress	19,336	16,544
Total	1,379,540	1,361,547
Accumulated Depreciation and Amortization	414,048	398,455
TOTAL - NET	965,492	963,092
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	5,434	5,438
Other Investments	351	422
TOTAL	5,785	5,860
CURRENT ASSETS		
Cash and Cash Equivalents	237	127
Other Cash Deposits	11	5
Advances to Affiliates	12,647	16,127
Accounts Receivable:		
Customers	23,885	22,130
Affiliated Companies	18,314	23,046
Accrued Unbilled Revenues	2,620	7,340
Miscellaneous	106	94
Allowance for Uncollectible Accounts	(2)	(34)
Fuel	10,663	6,551
Materials and Supplies	8,103	9,385
Risk Management Assets	21,980	19,845
Margin Deposits	3,148	1,960
Prepayments and Other	4,014	1,782
TOTAL	105,726	108,358
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	101,714	103,849
Other	23,163	14,558
Long-term Risk Management Assets	39,129	19,067
Emission Allowances	12,077	9,666
Deferred Property Taxes	3,605	7,036

Deferred Charges and Other	7,848	11,761
TOTAL	187,536	165,937
TOTAL ASSETS	$ 1,264,539	$ 1,243,247

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $50 par value per share:		
Authorized - 2,000,000 shares		
Outstanding - 1,009,000 shares	$ 50,450	$ 50,450
Paid-in Capital	208,750	208,750
Retained Earnings	82,886	70,555
Accumulated Other Comprehensive Income (Loss)	(10,731)	(8,775)
Total Common Shareholder's Equity	331,355	320,980
Long-term Debt:		
Nonaffiliated	427,716	428,310
Affiliated	20,000	80,000
Total Long-term Debt	447,716	508,310
TOTAL	779,071	829,290
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Affiliated	40,000	-
Accounts Payable:		
General	30,311	20,080
Affiliated Companies	24,766	24,899
Risk Management Liabilities	23,562	17,205
Taxes Accrued	7,717	9,248
Interest Accrued	6,795	6,754
Customer Deposits	16,304	12,309
Obligations Under Capital Leases	1,356	1,561
Other	7,505	9,038
TOTAL	158,316	101,094
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	226,829	227,536
Regulatory Liabilities:		
Asset Removal Costs	29,441	28,232
Deferred Investment Tax Credits	6,137	6,722
Other Regulatory Liabilities	20,464	15,622
Employee Benefits and Pension Obligations	12,198	17,729
Long-term Risk Management Liabilities	29,216	13,484
Obligations Under Capital Leases	2,366	2,802
Deferred Credits	501	736
TOTAL	327,152	312,863

Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 1,264,539	$ 1,243,247

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 12,331	$ 15,679
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	22,377	21,764
Deferred Income Taxes	2,482	4,616
Deferred Investment Tax Credits	(585)	(585)
Deferred Property Taxes	3,431	3,336
Pension Contributions	(6,092)	(113)
Pension and Postemployment Benefit Reserves	561	(814)
Mark-to-Market of Risk Management Contracts	(3,330)	1,064
Over/Under Fuel Recovery	(7,181)	(1,514)
(Gain)/Loss on Sale of Assets	(8)	1,051
Change in Other Noncurrent Assets	(731)	(8,360)
Change in Other Noncurrent Liabilities	3,725	9,035
Changes in Components of Working Capital:		
Accounts Receivable, Net	7,653	3,774
Fuel, Materials and Supplies	(2,830)	(2,398)
Accounts Payable	10,960	(2,173)
Taxes Accrued	(1,531)	3,670
Customer Deposits	3,995	2,777
Interest Accrued	41	(132)
Other Current Assets	(3,421)	1,430
Other Current Liabilities	(1,736)	(737)
Net Cash Flows From Operating Activities	40,111	51,370
INVESTING ACTIVITIES		
Construction Expenditures	(23,484)	(18,964)
Change in Other Cash Deposits, Net	(6)	6
Proceeds from Sale of Assets	9	1,538
Net Cash Flows Used For Investing Activities	(23,481)	(17,420)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Affiliated	-	20,000
Retirement of Long-term Debt - Affiliated	(20,000)	-
Changes in Advances to/from Affiliates, Net	3,480	(41,618)
Dividends Paid on Common Stock	-	(12,500)
Net Cash Flows Used For Financing Activities	(16,520)	(34,118)
Net Increase (Decrease) in Cash and Cash Equivalents	110	(168)

Cash and Cash Equivalents at Beginning of Period	127	863
Cash and Cash Equivalents at End of Period	$ 237	$ 695

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $13,942,000 and $14,625,000 and for income taxes was $3,761,000 and $658,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions in 2005 and 2004 were $230,000 and $387,000, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(862,000) and $(984,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
INDEX TO CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to KPCo's condensed financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to KPCo.

OHIO POWER COMPANY CO NSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$ 39
Changes in Gross Margin:		
Retail Margins	36	
Transmission Revenues	(6)	
Off-system Sales	6	
Other Revenues	2	
Total Change in Gross Margin		38
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	8	
Depreciation and Amortization	(9)	
Nonoperating Income and Expenses, Net	6	
Interest Charges	5	
Total Change in Operating Expenses and Other		10
Income Tax Expense		(16)
Second Quarter of 2005 Net Income		$ 71

Net Income increased $32 million in the second quarter of 2005. The key drivers of the increase were a $38 million increase in gross margin and an $8 million decrease in Other Operation and Maintenance partially offset by a $16 million increase in Income Tax Expense and a $9 million increase in Depreciation and Amortization.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins were $36 million higher than the prior period primarily due to:
  - a favorable variance of $16 million from the receipt of SO_2 allowances from Buckeye Power, Inc. under the Cardinal Station Allowance Agreement,
  - increased retail sales of $17 million due to increased industrial and residential sales from higher usage
  - and an increase of $8 million from capacity settlements under the Interconnection Agreement related to the increase in an affiliate's peak,
  - partially offset by decreased fuel margins of $5 million as a result of increased fuel costs.
- Transmission Revenues decreased $6 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.
- Margins from Off-system Sales increased $6 million primarily due to favorable price margins.

Operating Expenses and Other changed between years as follows:

- Depreciation and Amortization expense increased $9 million primarily due to the establishment of a $7 million regulatory liability to benefit low income customers and for economic development, as ordered in the rate stabilization plan.
- Other Operation and Maintenance expenses decreased $8 million primarily due to $4 million of expenses from the 2004 Amos Plant outage and $3 million of expenses related to major storms in the second quarter of 2004.
- Nonoperating Income and Expenses, Net increased $6 million primarily due to the establishment of a regulatory asset for carrying costs on environmental capital expenditures as a result of the rate stabilization plan order.
- Interest Charges decreased by $5 million primarily due to capitalized interest related to construction of the Mitchell and Cardinal plant scrubbers and the Mitchell plant Selective Catalytic Reduction (SCR) project that began after June 2004 in addition to refinancing debt maturities and optional redemptions with lower cost debt.

Income Tax

The effective tax rates for the second quarter of 2005 and 2004 were 32.9% 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, amortization of investment tax credits and state income taxes. The effective tax rates remained relatively flat for the comparative period.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income
(in millions)

Six Months Ended June 30, 2004 Net Income		$ 119
Changes in Gross Margin:		
Retail Margins	29	
Transmission Revenues	(13)	
Off-system Sales	11	
Other Revenues	2	
Total Change in Gross Margin		29
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	14	
Depreciation and Amortization	(11)	
Nonoperating Income and Expenses, Net	29	
Interest Charges	11	
Total Change in Operating Expenses and Other		43
Income Tax Expense		(20)
Six Months Ended June 30, 2005 Net Income		$ 171

Net Income increased $52 million in 2005. The increase is primarily due to a $29 million increase in gross margin, a $29 million increase in Nonoperating Income and Expenses, Net and a $14 million decrease in Other Operation and Maintenance offset by a $20 million increase in Income Tax Expense.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins were $29 million higher than the prior period primarily due to:
  - a favorable variance of $18 million from the receipt of SO_2 allowances from Buckeye Power, Inc. under the

Cardinal Station Allowance Agreement,
- increased retail sales of $16 million due to increased industrial and residential sales from higher usage
- and an increase of $11 million from capacity settlements under the Interconnection Agreement related to the increase in an affiliate's peak,
- partially offset by decreased fuel margins of $16 million as a result of increased fuel costs.

- Transmission Revenues decreased $13 million primarily due to the loss of through and out rates, net of replacement SECA rates. See "FERC Order on Regional Through and Out Rates" for additional discussion of these FERC rate changes.
- Margins from Off-system Sales increased $11 million primarily due to favorable price margins.

Operating Expenses and Other changed between years as follows:

- Nonoperating Income and Expenses, Net increased $29 million primarily due to the establishment of a regulatory asset for carrying costs on environmental capital expenditures as a result of the rate stabilization plan order.
- Other Operation and Maintenance expenses decreased $14 million primarily due to the settlement and cancellation of the COLI policy of $7 million in February 2005 and a decrease in administrative expenses of $7 million related to the Gavin scrubber.
- Interest Charges decreased by $11 million primarily due to capitalized interest related to construction of the Mitchell and Cardinal plant scrubbers and the Mitchell plant SCR project that began after June 2004. Interest Charges also decreased due to refinancing debt maturities and optional redemptions with lower cost debt.
- Depreciation and Amortization expense increased $11 million due to the establishment of a $7 million regulatory liability to benefit low income customers and for economic development, as ordered in the rate stabilization plan. The increase is also attributable to a higher depreciation base in electric utility plants.

Income Tax

The effective tax rates for the first six months of 2005 and 2004 were 33.0% and 35.0%, 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, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in permanent differences.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the six months ended June 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 9,300	$ 7,233
Cash Flows From (Used For):		
Operating Activities	182,835	303,385
Investing Activities	(288,713)	(78,441)

Financing Activities	97,931	(225,783)
Net Decrease in Cash and Cash Equivalents	(7,947)	(839)
Cash and Cash Equivalents at End of Period	$ 1,353	$ 6,394

Operating Activities

Our Net Cash Flows From Operating Activities were $183 million for the first six months of 2005. We produced income of $171 million during the period and a noncash expense item of $154 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital primarily relates to a $93 million decrease in Taxes Accrued due to 2004 tax payments made in the second quarter of 2005 for federal income tax and personal property tax.

Our Net Cash Flows From Operating Activities were $303 million for the first six months of 2004. We produced income of $119 million during the period and a noncash expense item of $142 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital primarily relates to a $21 million increase in Taxes Accrued primarily due to increased accrued federal income taxes offset by decreased accrued personal property taxes.

Investing Activities

Our Net Cash Flows Used for Investing Activities for the first six months of 2005 were $289 million primarily due to Construction Expenditures focused primarily on environmental upgrades, as well as projects to improve service reliability for transmission and distribution. For the remainder of 2005, we expect our Construction Expenditures to be approximately $470 million.

Our Net Cash Flows Used For Investing Activities for the first six months of 2004 were $78 million. The change is primarily due to Construction Expenditures offset by a cash deposit that we used to redeem $50 million of debt in January 2004.

Financing Activities

Our Net Cash flows From Financing Activities during the first six months of 2005 were $98 million primarily due to increased borrowings from the Utility Money Pool.

Our Net Cash Flows Used For Financing Activities during the first six months of 2004 were $226 million primarily due to decreased repayments of borrowings from the Utility Money Pool and dividend payments on Common Stock.

Financing Activity

In January 2005, we redeemed $5 million of 5.90% Cumulative Preferred Stock Subject to Mandatory Redemption. Additionally, long-term debt issuances and retirements during the six months ended June 30, 2005 were:

<u>Issuances</u>

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	

Installment Purchase Contracts	$ 54,500	Variable	2029
Installment Purchase Contracts	54,500	Variable	2028
Installment Purchase Contracts	54,500	Variable	2028
Installment Purchase Contracts	54,500	Variable	2028

Retirements and Principal Payments

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Installment Purchase Contracts	$ 51,000	6.375	2029
Installment Purchase Contracts	51,000	6.375	2029
Installment Purchase Contracts	40,000	Variable	2028
Installment Purchase Contracts	40,000	Variable	2028
Installment Purchase Contracts	18,000	Variable	2029
Installment Purchase Contracts	18,000	Variable	2029
Notes Payable	2,927	6.81	2008
Notes Payable	3,250	6.27	2009

Liquidity

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

Summary Obligation Information

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

Significant Factors

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

Critical Accounting Estimates

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

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

Roll-Forward of MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	47,777
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(13,297)
Fair Value of New Contracts When Entered During the Period (b)		835
Net Option Premiums Paid/(Received) (c)		(372)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		9,576
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		44,519
Net Cash Flow Hedge Contracts (f)		(8,836)
DETM Assignment (g)		(13,536)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	22,147

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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 Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(g) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheets
As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 73,367	$ 669	$ -	$ 74,036
Noncurrent Assets	119,965	72	-	120,037
Total MTM Derivative Contract Assets	193,332	741	-	194,073
Current Liabilities	(67,887)	(9,007)	(4,554)	(81,448)
Noncurrent Liabilities	(80,926)	(570)	(8,982)	(90,478)
Total MTM Derivative Contract Liabilities	(148,813)	(9,577)	(13,536)	(171,926)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 44,519	$ (8,836)	$ (13,536)	$ 22,147

(a) Does not include Cash Flow Hedges.
(b) See "Natural Gas Contracts with DETM" section in Note 17 of the 2004 Annual Report.
(c) 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (7,535)	$ (61)	$ 5,975	$ -	$ -	$ -	$ (1,621)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	17,902	22,301	8,397	8,390	-	-	56,990
Prices Based on Models and Other Valuation Methods (b)	(8,485)	(12,533)	(3,813)	1,126	7,124	5,731	(10,850)

Total	$ 1,882	$ 9,707	$10,559	$ 9,516	$ 7,124	$ 5,731	$ 44,519

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

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

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $6.1 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

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

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

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power	Interest Rate	Foreign Currency	Total
Beginning Balance December 31, 2004	$ 1,599	$ -	$ (358)	$ 1,241
Changes in Fair Value (a)	(3,130)	(1,001)	-	(4,131)
Reclassifications from AOCI to Net Income (b)	(2,975)	-	7	(2,968)
Ending Balance June 30, 2005	$ (4,506)	$ (1,001)	$ (351)	$ (5,858)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $4,432 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$831	$994	$485	$285	$464	$1,513	$652	$223

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $128 million and $146 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 450,122	$ 399,535	$ 906,353	$ 843,264
Sales to AEP Affiliates	156,607	135,413	308,446	281,901
TOTAL	606,729	534,948	1,214,799	1,125,165
OPERATING EXPENSES				
Fuel for Electric Generation	168,693	145,503	348,954	311,774
Purchased Electricity for Resale	22,423	14,155	41,185	26,338
Purchased Electricity from AEP Affiliates	25,093	23,169	50,711	42,472
Other Operation	92,950	96,224	166,733	187,320
Maintenance	51,355	56,733	97,110	90,784
Depreciation and Amortization	79,941	70,388	153,888	142,170
Taxes Other Than Income Taxes	43,686	43,646	90,828	90,836
Income Taxes	32,064	22,220	70,635	62,202
TOTAL	516,205	472,038	1,020,044	953,896
OPERATING INCOME	90,524	62,910	194,755	171,269
Nonoperating Income	50,231	52,704	105,203	69,455
Carrying Costs Income	7,511	178	29,548	357
Nonoperating Expenses	48,027	49,231	93,054	57,300
Nonoperating Income Tax Expense (Credit)	2,920	(3,120)	13,487	1,967
Interest Charges	25,838	30,898	52,001	62,867
NET INCOME	71,481	38,783	170,964	118,947
Preferred Stock Dividend Requirements (Including Other Expense)	357	183	540	366
EARNINGS APPLICABLE TO COMMON STOCK	$ 71,124	$ 38,600	$ 170,424	$ 118,581

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 321,201	$ 462,484	$ 729,147	$ (48,807)	$1,464,025
Common Stock Dividends			(114,115)		(114,115)
Preferred Stock Dividends			(366)		(366)
TOTAL					1,349,544
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,746				(3,242)	(3,242)
Minimum Pension Liability, Net of Tax of $2,123				(3,942)	(3,942)
NET INCOME			118,947		118,947
TOTAL COMPREHENSIVE INCOME					111,763
JUNE 30, 2004	$ 321,201	$ 462,484	$ 733,613	$ (55,991)	$1,461,307
DECEMBER 31, 2004	$ 321,201	$ 462,485	$ 764,416	$ (74,264)	$1,473,838
Common Stock Dividends			(14,999)		(14,999)
Preferred Stock Dividends			(366)		(366)
Other		4,151	(174)		3,977
TOTAL					1,462,450
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,823				(7,099)	(7,099)
NET INCOME			170,964		170,964
TOTAL COMPREHENSIVE INCOME					163,865
JUNE 30, 2005	$ 321,201	$ 466,636	$ 919,841	$ (81,363)	$1,626,315

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 4,240,563	$ 4,127,284
Transmission	995,634	978,492
Distribution	1,228,611	1,202,550
General	240,018	248,749
Construction Work in Progress	342,832	240,957
Total	7,047,658	6,798,032
Accumulated Depreciation and Amortization	2,657,146	2,617,238
TOTAL - NET	4,390,512	4,180,794
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	44,438	44,774
Other	8,856	13,409
TOTAL	53,294	58,183
CURRENT ASSETS		
Cash and Cash Equivalents	1,353	9,300
Other Cash Deposits	31	37
Advances to Affiliates	-	125,971
Accounts Receivable:		
Customers	108,026	98,951
Affiliated Companies	144,638	144,175
Accrued Unbilled Revenues	14,754	10,641
Miscellaneous	453	7,626
Allowance for Uncollectible Accounts	(114)	(93)
Fuel	111,013	70,309
Materials and Supplies	58,962	55,569
Emissions Allowances	38,170	95,303
Risk Management Assets	74,036	79,541
Margin Deposits	10,174	7,056
Prepayments and Other	14,642	10,492
TOTAL	576,138	714,878
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	172,933	169,866
Transition Regulatory Assets	182,469	225,273
Unamortized Loss on Reacquired Debt	14,197	11,046
Other	74,122	22,189

Long-term Risk Management Assets	120,037	66,727
Deferred Property Taxes	37,960	70,214
Deferred Charges and Other Assets	62,845	74,095
TOTAL	664,563	639,410
TOTAL ASSETS	$ 5,684,507	$ 5,593,265

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity		
Common Stock - No par value:		
Authorized - 40,000,000 shares		
Outstanding - 27,952,473 shares	$ 321,201	$ 321,201
Paid-in Capital	466,636	462,485
Retained Earnings	919,841	764,416
Accumulated Other Comprehensive Income (Loss)	(81,363)	(74,264)
Total Common Shareholder's Equity	1,626,315	1,473,838
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,641	16,641
Total Shareholders' Equity	1,642,956	1,490,479
Long-term Debt:		
Nonaffiliated	1,593,273	1,598,706
Affiliated	200,000	400,000
Total Long-term Debt	1,793,273	1,998,706
TOTAL	3,436,229	3,489,185
Minority Interest	12,906	14,083
CURRENT LIABILITIES		
Short-term Debt - Nonaffiliated	14,352	23,498
Long-term Debt Due Within One Year - Affiliated	200,000	-
Long-term Debt Due Within One Year - Nonaffiliated	12,354	12,354
Cumulative Preferred Stock Subject to Mandatory Redemption	-	5,000
Advances from Affiliates	11,528	-
Accounts Payable:		
General	164,615	143,247
Affiliated Companies	76,171	116,615
Customer Deposits	32,258	22,620
Taxes Accrued	139,726	233,026
Interest Accrued	37,249	39,254
Risk Management Liabilities	81,448	70,311
Obligations Under Capital Leases	8,847	9,081
Other	91,531	74,977
TOTAL	870,079	749,983
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	910,767	943,465
Regulatory Liabilities:		

Asset Removal Costs	107,043	102,875
Deferred Investment Tax Credits	12,040	12,539
Other	48,864	-
Long-term Risk Management Liabilities	90,478	46,261
Deferred Credits	23,057	24,377
Employee Benefits and Pension Obligations	86,939	126,825
Obligations Under Capital Leases	33,037	31,652
Asset Retirement Obligations	47,402	45,606
Other	5,666	6,414
TOTAL	1,365,293	1,340,014
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,684,507	$ 5,593,265

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 170,964	$ 118,947
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	153,888	142,170
Accretion Expense	1,796	1,682
Deferred Income Taxes	9,923	4,400
Deferred Investment Tax Credits	(499)	(1,523)
Deferred Property Taxes	32,254	30,792
Pension and Postemployment Benefit Reserves	128	1,528
Mark-to-Market of Risk Management Contracts	(2,271)	4,819
Pension Contributions	(40,013)	(191)
Carrying Costs Income	(29,548)	(357)
Change in Other Noncurrent Assets	(13,611)	(20,362)
Change in Other Noncurrent Liabilities	(1,810)	(5,217)
Changes in Components of Working Capital:		
Accounts Receivable, Net	(6,457)	(1,616)
Fuel, Materials and Supplies	(44,097)	(12,888)
Accounts Payable	(28,330)	4,921
Taxes Accrued	(93,300)	20,692
Customer Deposits	9,638	10,791
Interest Accrued	(2,005)	(359)
Other Current Assets	49,864	11,050
Other Current Liabilities	16,321	(5,894)
Net Cash Flows From Operating Activities	182,835	303,385
INVESTING ACTIVITIES		
Construction Expenditures	(296,048)	(130,495)
Change in Other Cash Deposits, Net	6	50,952
Proceeds from Sale of Assets	7,329	1,102
Net Cash Flows Used For Investing Activities	(288,713)	(78,441)
FINANCING ACTIVITIES		
Change in Short-term Debt, Net	(9,146)	(4,402)
Issuance of Long-term Debt - Nonaffiliated	214,120	-
Issuance of Long-term Debt - Affiliated	-	200,000
Retirement of Long-term Debt - Nonaffiliated	(224,177)	(204,427)
Retirement of Cumulative Preferred Stock	(5,000)	(2,251)
Changes in Advances to/from Affiliates, Net	137,499	(100,222)
Dividends Paid on Common Stock	(14,999)	(114,115)

Dividends Paid on Cumulative Preferred Stock	(366)	(366)
Net Cash Flows From (Used For) Financing Activities	97,931	(225,783)
Net Decrease in Cash and Cash Equivalents	(7,947)	(839)
Cash and Cash Equivalents at Beginning of Period	9,300	7,233
Cash and Cash Equivalents at End of Period	$ 1,353	$ 6,394

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $52,403,000 and $59,407,000 and for income taxes was $114,782,000 and $(8,420,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $7,210,000 and $6,846,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $9,253,000 and $(3,280,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

The condensed notes to OPCo's condensed consolidated financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to OPCo.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income (in millions)

Second Quarter of 2004 Net Income		$ 7
Changes in Gross Margin:		
Retail Margins	(1)	
Off-system Sales	1	
Total Change in Gross Margin		-
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	9	
Taxes Other Than Income Taxes	4	
Interest Charges	1	
Total Change in Operating Expenses and Other		14
Income Tax Expense		(3)
Second Quarter of 2005 Net Income		$ 18

Net Income increased $11 million to $18 million in the second quarter of 2005. The key drivers were a $9 million decrease in operation and maintenance expenses and a $4 million decrease in Taxes Other Than Income Taxes, partially offset by a $3 million increase in Income Tax Expense.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $1 million primarily due to a $3 million decrease in net fuel revenue/fuel expense, offset by a $2 million increase in retail base revenue due to slightly higher volumes.
- Margins from Off-system Sales increased by $1 million primarily due to higher capacity sales and by slightly higher optimization activity.

Operating Expenses and Other decreased between years as follows:

- Other Operation and Maintenance expenses decreased $9 million primarily attributed to the higher cost of scheduled plant maintenance and overhead line maintenance due to storm damage, both in 2004.
- Taxes Other Than Income Taxes decreased $4 million primarily due to a prior year adjustment of property related taxes.
- Interest Charges decreased $1 million primarily due to the retirement of higher rate First Mortgage Bonds and Trust Preferred Securities in 2004 replaced by lower rate Senior Unsecured Notes.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were 22.8% and 21.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income (Loss)
(in millions)

Six Months Ended June 30, 2004 Net Loss		$	(2)
Changes in Gross Margin:			
Retail Margins	(5)		
Off-system Sales	4		
Total Change in Gross Margin			(1)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	24		
Taxes Other Than Income Taxes	4		
Interest Charges	3		
Nonoperating Income and Expense, Net	1		
Total Change in Operating Expenses and Other			32
Income Tax Expense			(10)
Six Months Ended June 30, 2005 Net Income		$	19

Net Income increased $21 million to $19 million for the six months ended June 30, 2005. The key drivers were a $24 million decrease in operation and maintenance expenses and a $4 million decrease in Taxes Other Than Income Taxes, partially offset by a $10 million increase in Income Tax Expense.

The major components of our decrease in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased by $5 primarily due to a $6 million decrease in net fuel revenue/fuel expense, offset by a $1 million increase in retail base revenue due to slightly higher volumes.
- Margins from Off-system Sales increased by $4 million primarily due to higher margins of $3 million and higher capacity sales of $1 million.

Operating Expenses and Other decreased between years as follows:

- Other Operation and Maintenance expenses decreased $24 million. Transmission related expenses decreased $7 million primarily due to adjustments in 2004 for affiliated OATT and ancillary services resulting from revised ERCOT data for the years 2001 through 2003 of approximately $5 million. Distribution expenses decreased $3 million resulting primarily from a 2004 labor settlement. Administrative and general expenses decreased approximately $7 million due to lower outside services and employee related expenses, offset in part by increased customer related expense of $2 million. Maintenance decreased $10 million primarily attributed to the higher cost of scheduled power plant maintenance and overhead line maintenance due to storm damage, both in 2004.
- Interest Charges decreased $3 million primarily due to the retirement of higher rate First Mortgage Bonds and Trust Preferred Securities in 2004 replaced by lower rate Senior Unsecured Notes.

Income Taxes

The effective tax rates for the six months ended June 30, 2005 and 2004 were 18.7% and 78.1%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The change in the effective tax rate from the comparative period is primarily due to higher pretax income in 2005 and state and local income taxes, offset in part by federal income tax adjustments.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

Long-term issuances and retirements during the first six months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 75,000	4.70	2011

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
First Mortgage Bonds	$ 50,000	6.50	2005

Liquidity

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

Summary Obligation Information

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

Significant Factors

Oklahoma Regulatory Activity

Rate Review

We have 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 we may not file for a base rate increase before April 1, 2006. The OCC issued an order approving the stipulation on May 2, 2005, allowing for the implementation of new base rates in June 2005.

Fuel and Purchased Power

In 2002, we 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, we offered to the OCC to collect those reallocated costs over 18 months. In August 2003, the OCC Staff filed testimony recommending we recover $42 million of the reallocation over three years. Subsequently the OCC expanded the case to include a full prudence review of our 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 the alleged improperly allocated off-system sales margins between AEP East and AEP West companies. Their overall recommendations related to the allocation would result in an increase in off-system sales margins, and thus a reduction to our recoverable fuel costs through June 2005, of an amount between $38 million and $47 million.

On June 10, 2005, the OCC decided to have its staff conduct a prudence review of our 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.

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	14,771
(Gain) Loss from Contracts Realized/Settled During the Period (a)		172
Fair Value of New Contracts When Entered During the Period (b)		-
Net Option Premiums Paid/(Received) (c)		(56)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		(11,050)
Total MTM Risk Management Contract Net Assets		3,837
Net Cash Flow Hedge Contracts (f)		(849)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	2,988

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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 Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheets

As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 6,171	$ 33	$ 6,204
Noncurrent Assets	7,613	9	7,622
Total MTM Derivative Contract Assets	13,784	42	13,826
Current Liabilities	(5,772)	(814)	(6,586)
Noncurrent Liabilities	(4,175)	(77)	(4,252)
Total MTM Derivative Contract Liabilities	(9,947)	(891)	(10,838)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,837	$ (849)	$ 2,988

(a) Does not include Cash Flow 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 Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (1,016)	$ (8)	$ 805	$ -	$ -	$ -	$ (219)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,162	2,815	830	987	-	-	6,794
Prices Based on Models and Other Valuation Methods (b)	(1,109)	(2,028)	(869)	(88)	620	736	(2,738)
Total	$ 37	$ 779	$ 766	$ 899	$ 620	$ 736	$ 3,837

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external

sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $442 thousand of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

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

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,000	$ (600)	$ 400
Changes in Fair Value (a)	(1,122)	48	(1,074)
Reclassifications from AOCI to Net Income (b)	(422)	13	(409)
Ending Balance June 30, 2005	$ (544)	$ (539)	$ (1,083)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $611 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$112	$134	$65	$38	$238	$778	$335	$115

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $34 million and $35 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 272,693	$ 228,864	$ 523,061	$ 432,907
Sales to AEP Affiliates	13,650	2,954	16,282	6,096
TOTAL	286,343	231,818	539,343	439,003
OPERATING EXPENSES				
Fuel for Electric Generation	129,536	87,006	263,707	176,080
Fuel from Affiliates for Electric Generation	-	-	-	11
Purchased Energy for Resale	30,132	5,583	44,925	14,751
Purchased Electricity from AEP Affiliates	15,389	28,200	38,234	55,099
Other Operation	36,287	36,979	66,472	80,374
Maintenance	14,153	22,875	25,512	35,997
Depreciation and Amortization	22,247	22,159	44,866	44,335
Taxes Other Than Income Taxes	6,061	9,727	15,738	19,544
Income Taxes (Credits)	5,657	2,429	4,805	(4,904)
TOTAL	259,462	214,958	504,259	421,287
OPERATING INCOME	26,881	16,860	35,084	17,716
Nonoperating Income	524	127	1,002	371
Nonoperating Expenses	385	762	936	1,304
Nonoperating Income Tax Credit	171	467	421	859
Interest Charges	8,621	9,301	16,496	19,254
NET INCOME (LOSS)	18,570	7,391	19,075	(1,612)
Preferred Stock Dividend Requirements	53	53	106	106
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 18,517	$ 7,338	$ 18,969	$ (1,718)

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 157,230	$ 230,016	$ 139,604	$ (43,842)	$ 483,008
Gain on Reacquired Preferred Stock			2		2
Common Stock Dividends			(17,500)		(17,500)
Preferred Stock Dividends			(106)		(106)
TOTAL					465,404
COMPREHENSIVE LOSS					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $283				(526)	(526)
NET LOSS			(1,612)		(1,612)
TOTAL COMPREHENSIVE LOSS					(2,138)
JUNE 30, 2004	$ 157,230	$ 230,016	$ 120,388	$ (44,368)	$ 463,266
DECEMBER 31, 2004	$ 157,230	$ 230,016	$ 141,935	$ 75	$ 529,256
Common Stock Dividends			(17,000)		(17,000)
Preferred Stock Dividends			(106)		(106)
TOTAL					512,150
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $798				(1,483)	(1,483)
NET INCOME			19,075		19,075
TOTAL COMPREHENSIVE INCOME					17,592
JUNE 30, 2005	$ 157,230	$ 230,016	$ 143,904	$ (1,408)	$ 529,742

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,069,477	$ 1,072,022
Transmission	472,944	468,735
Distribution	1,114,572	1,089,187
General	200,682	200,044
Construction Work in Progress	54,459	41,028
Total	2,912,134	2,871,016
Accumulated Depreciation and Amortization	1,131,114	1,117,113
TOTAL - NET	1,781,020	1,753,903
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,594	4,401
Other Investments	-	81
TOTAL	4,594	4,482
CURRENT ASSETS		
Cash and Cash Equivalents	778	91
Other Cash Deposits	6	188
Advances to Affiliates	7,084	-
Accounts Receivable:		
Customers	18,358	34,002
Affiliated Companies	39,598	46,399
Miscellaneous	7,798	6,984
Allowance for Uncollectible Accounts	-	(76)
Fuel Inventory	17,711	14,268
Materials and Supplies	38,797	35,485
Risk Management Assets	6,204	21,388
Regulatory Asset for Under-Recovered Fuel Costs	-	366
Margin Deposits	1,128	2,881
Prepayments and Other	2,786	1,378
TOTAL	140,248	163,354
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	13,581	14,705
Other	20,470	17,246
Long-term Risk Management Assets	7,622	14,477
Prepaid Pension Obligations	82,411	82,419
Deferred Property Taxes	16,245	-

Deferred Charges and Other Assets	16,841	18,232
TOTAL	157,170	147,079
TOTAL ASSETS	$ 2,083,032	$ 2,068,818

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $15 par value per share:		
Authorized - 11,000,000 shares		
Issued - 10,482,000 shares		
Outstanding - 9,013,000 shares	$ 157,230	$ 157,230
Paid-in Capital	230,016	230,016
Retained Earnings	143,904	141,935
Accumulated Other Comprehensive Income (Loss)	(1,408)	75
Total Common Shareholder's Equity	529,742	529,256
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Total Shareholders' Equity	535,004	534,518
Long-term Debt:		
Nonaffiliated	521,041	446,092
Affiliated	-	50,000
Total Long-term Debt	521,041	496,092
TOTAL	1,056,045	1,030,610
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	-	50,000
Long-term Debt Due Within One Year - Affiliated	50,000	-
Advances from Affiliates	-	55,002
Accounts Payable:		
General	112,435	71,442
Affiliated Companies	67,002	58,632
Customer Deposits	34,774	33,757
Taxes Accrued	29,996	18,835
Interest Accrued	3,324	4,023
Risk Management Liabilities	6,586	13,705
Regulatory Liability for Over-Recovered Fuel Costs	1,185	-
Obligations Under Capital Leases	603	537
Other	21,083	30,477
TOTAL	326,988	336,410
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	387,520	384,090
Long-term Risk Management Liabilities	4,252	7,455
Regulatory Liabilities:		
Asset Removal Costs	233,774	220,298
Deferred Investment Tax Credits	27,724	28,620

SFAS 109 Regulatory Liability, Net	20,734	21,963
Unrealized Gain on Forward Commitments	6,703	19,676
Obligations Under Capital Leases	1,111	747
Deferred Credits and Other	18,181	18,949
TOTAL	699,999	701,798
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,083,032	$ 2,068,818

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income (Loss)	$ 19,075	$ (1,612)
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	44,866	44,335
Deferred Property Taxes	(16,245)	(17,295)
Deferred Income Taxes	2,998	11,043
Deferred Investment Tax Credits	(896)	(895)
Mark-to-Market of Risk Management Contracts	10,934	10,237
Fuel Recovery	1,551	(12,683)
Change in Other Noncurrent Assets	(16,856)	(4,152)
Change in Other Noncurrent Liabilities	(1,943)	(4,605)
Changes in Components of Working Capital:		
Accounts Receivable, Net	21,555	(5,441)
Fuel, Materials and Supplies	(6,755)	(3,534)
Accounts Payable	49,958	20,508
Customer Deposits	1,017	2,952
Taxes Accrued	11,161	7,911
Interest Accrued	(699)	(259)
Other Current Assets	343	3,513
Other Current Liabilities	(9,326)	(13,898)
Net Cash Flows From Operating Activities	110,738	36,125
INVESTING ACTIVITIES		
Construction Expenditures	(55,449)	(36,713)
Change in Other Cash Deposits, Net	182	3,565
Proceeds from Sale of Assets	-	458
Net Cash Flows Used For Investing Activities	(55,267)	(32,690)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	74,408	83,129
Retirement of Long-term Debt	(50,000)	(111,020)
Reacquired Preferred Stock	-	(3)
Changes in Advances to/from Affiliates, Net	(62,086)	42,170
Dividends Paid on Common Stock	(17,000)	(17,500)
Dividends Paid on Cumulative Preferred Stock	(106)	(106)
Net Cash Flows Used For Financing Activities	(54,784)	(3,330)
Net Increase in Cash and Cash Equivalents	687	105
Cash and Cash Equivalents at Beginning of Period	91	3,738

Cash and Cash Equivalents at End of Period	$ 778	$ 3,843

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $15,028,000 and $17,600,000 and for income taxes was $3,590,000 and $(2,695,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $738,000 and $337,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(595,000) and $(174,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

Results of Operations

Second Quarter of 2005 Compared to Second Quarter of 2004

Reconciliation of Second Quarter of 2004 to Second Quarter of 2005 Net Income
(in millions)

Second Quarter of 2004 Net Income		$ 28
Changes in Gross Margin:		
Retail Margins (a)	(14)	
Off-system Sales	3	
Other Revenues	1	
Total Change in Gross Margin		(10)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(6)	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	(1)	
Interest Charges	1	
Total Change in Operating Expenses and Other:		(7)
Income Tax Expense		8
Second Quarter of 2005 Net Income		$ 19

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

Net Income decreased $9 million to $19 million in the second quarter of 2005. The key drivers were a $10 million decrease in gross margin and a $7 million net increase in operating expenses and other, partially offset by an $8 million decrease in Income Tax Expense.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased $14 million primarily due to a $22 million decrease in net fuel revenue/fuel expense, of which $11 million is increased capacity expense, offset by an increase in retail base revenue of $5 million and an increase of $3 million in wholesale base revenue, due to higher volumes.
- Margins from Off-system Sales increased $3 million primarily due to increased capacity and affiliated sales margins.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $6 million primarily due to increased maintenance expense of $4 million resulting from extended power plant outages, increased production related expense and higher administrative and general expenses.

Income Taxes

The effective tax rates for the second quarter of 2005 and 2004 were 22.1% and 33.2%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to state and local income taxes, changes in permanent differences and federal income tax adjustments.

Six Months Ended June 30, 2005 Compared to Six Months Ended June 30, 2004

Reconciliation of Six Months Ended June 30, 2004 to Six Months Ended June 30, 2005 Net Income (in millions)

Six Months Ended June 30, 2004 Net Income		$	33
Changes in Gross Margin:			
Retail Margins (a)	(9)		
Off-system Sales	2		
Transmission Revenues	(1)		
Other Revenues	2		
Total Change in Gross Margin			(6)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	-		
Depreciation and Amortization	(2)		
Interest Charges	3		
Total Change in Operating Expenses and Other:			1
Income Tax Expense			4
Six Months Ended June 30, 2005 Net Income		$	32

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

Net Income decreased $1 million to $32 million for the six months ended June 30, 2005. The key driver was a $6 million decrease in gross margin, offset by a $4 million decrease in Income Tax Expense.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail Margins decreased $9 million primarily due to a $24 million decrease in net fuel revenue/fuel expense, of which $13 million is increased capacity expense, offset by an increase in retail base revenue of $5 million and an increase of $10 million in wholesale base revenue, due to higher volumes.
- Margins from Off-system Sales increased $2 million primarily due to higher optimization activity.
- Transmission Revenues decreased $1 million primarily due to reduced SPP revenues.

Operating Expenses and Other changed between years as follows:

- Operation expenses decreased $3 million primarily due to a $6 million adjustment in 2004 for affiliated OATT and ancillary services resulting from revised ERCOT data for the years 2001 through 2003, offset in part by $3 million of higher production plant related expenses. Maintenance expense increased $4 million primarily due to major power plant outages in 2005.

- Interest Charges decreased $3 million primarily due to refinancing debt maturities and optional redemptions with lower cost debt.

Income Taxes

The effective tax rates for the six months ended 2005 and 2004 were 23.9% and 29.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to state income taxes and changes in permanent differences.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	A-	A
Senior Unsecured Debt	Baa1	BBB	A-

Cash Flow

Cash flows for the six months ended June 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,308	$ 5,676
Cash Flows From (Used For):		
Operating Activities	98,139	112,966
Investing Activities	(65,750)	(42,760)
Financing Activities	(30,106)	(64,280)
Net Increase in Cash and Cash Equivalents	2,283	5,926
Cash and Cash Equivalents at End of Period	$ 4,591	$ 11,602

Operating Activities

Our Net Cash Flows From Operating Activities were $98 million in 2005. We produced income of $32 million during the period and noncash expense items of $66 million for Depreciation and Amortization offset by $(19) million in amortization expense related to Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Receivable, Net and Accounts Payable. Accounts Receivable, Net decreased $12 million related to decreased affiliated energy transactions. Accounts Payable increased $28 million due primarily to higher vendor related payables and higher energy transactions.

Our Net Cash Flows From Operating Activities were $113 million in 2004. We produced income of $33 million during the period and noncash expense items of $63 million for Depreciation and Amortization offset by $(19) million in amortization expense related to Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Receivable, Net, Taxes Accrued and Interest Accrued. Accounts Receivables, Net increased $4 million related to affiliated energy transactions. Taxes Accrued increased $46 million primarily due to the annual tax accruals related to 2004 property taxes and by an increase of income tax related accruals. Interest Accrued decreased $5 million primarily related to retirement of debt.

Investing Activities

Net Cash Flows Used For Investing Activities during 2005 and 2004 were $66 million and $43 million, respectively. They were comprised of Construction Expenditures related to projects for improved transmission and distribution service reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $130 million.

Financing Activities

Net Cash Flows Used For Financing Activities were $30 million during 2005. During the six months ended June 30, 2005, we loaned $149 million to the Utility Money Pool, issued Senior Unsecured Notes for $150 million for the purpose of funding the July 1, 2005 maturity of our $200 million Senior Unsecured Notes and retired $5 million of Note Payable. Common stock dividends were $25 million.

Net Cash Flows Used For Financing Activities were $64 million during 2004. During the six months ended June 30, 2004, we increased our Utility Money Pool borrowing by $93 million, retired $120 million of First Mortgage Bonds, retired $5 million of Note Payable, replaced $95 million of Installment Purchase Contracts with lower variable interest rate long-term debt of the same principal amount and paid $30 million in common stock dividends.

Financing Activity

Long-term issuances and retirements during the first six months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 150,000(a)	4.90	2015

(a) Represents issuance in advance of maturity of $200 million, 4.50% Senior Unsecured Notes on July 1, 2005.

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Note Payable	$ 3,415	4.47	2011
Note Payable	1,500	Variable	2008

Liquidity

We have solid investment grade ratings, which when desired provide us ready access to capital markets in order to issue new debt, refinance short-term debt or refinance long-term debt maturities. In addition, we participate in the

Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

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

Significant Factors

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

Critical Accounting Estimates

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

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	17,527
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(3,428)
Fair Value of New Contracts When Entered During the Period (b)		47
Net Option Premiums Paid/(Received) (c)		(84)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(1,087)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		(8,479)
Total MTM Risk Management Contract Net Assets		4,496
Net Cash Flow Hedge Contracts (f)		(1,311)
Total MTM Risk Management Contract Net Assets at June 30, 2005	$	3,185

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized 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 that were 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 Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to

Condensed Consolidated Balance Sheets
As of June 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 7,417	$ 39	$ 7,456
Noncurrent Assets	9,084	11	9,095
Total MTM Derivative Contract Assets	16,501	50	16,551
Current Liabilities	(6,940)	(1,098)	(8,038)
Noncurrent Liabilities	(5,065)	(263)	(5,328)
Total MTM Derivative Contract Liabilities	(12,005)	(1,361)	(13,366)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,496	$ (1,311)	$ 3,185

(a) Does not include Cash Flow 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

The table presenting maturity and source of fair value of MTM risk management contract net assets 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
Fair Value of Contracts as of June 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009 (c)	Total (d)
Prices Actively Quoted - Exchange Traded Contracts	$ (1,207)	$ (10)	$ 957	$ -	$ -	$ -	$ (260)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	2,564	3,373	950	1,174	-	-	8,061
Prices Based on Models and Other Valuation Methods (b)	(1,319)	(2,439)	(1,055)	(104)	737	875	(3,305)
Total	$ 38	$ 924	$ 852	$ 1,070	$ 737	$ 875	$ 4,496

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

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

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $525 thousand of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow Hedges.

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

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

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

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2005
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,188	$ (2,008)	$ (820)
Changes in Fair Value (a)	(1,334)	(3,378)	(4,712)
Reclassifications from AOCI to Net Income (b)	(500)	-	(500)
Ending Balance June 30, 2005	$ (646)	$ (5,386)	$ (6,032)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at June 30, 2005. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,134 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Six Months Ended June 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$133	$159	$78	$46	$283	$923	$398	$136

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $32 million and $31 million at June 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Six Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 326,175	$ 251,550	$ 556,049	$ 465,500
Sales to AEP Affiliates	6,837	17,498	23,959	39,709
TOTAL	333,012	269,048	580,008	505,209
OPERATING EXPENSES				
Fuel for Electric Generation	116,167	94,245	206,277	183,068
Purchased Electricity for Resale	32,803	(4,008)	46,183	1,926
Purchased Electricity from AEP Affiliates	22,003	7,113	27,867	14,420
Other Operation	47,115	44,593	91,564	94,861
Maintenance	27,645	24,011	43,360	39,659
Depreciation and Amortization	33,257	31,979	65,650	63,264
Taxes Other Than Income Taxes	15,887	15,148	31,550	31,715
Income Taxes	5,861	14,439	10,457	14,570
TOTAL	300,738	227,520	522,908	443,483
OPERATING INCOME	32,274	41,528	57,100	61,726
Nonoperating Income	991	792	2,310	2,195
Nonoperating Expenses	617	723	1,091	1,334
Nonoperating Income Tax Credit	371	541	571	897
Interest Charges	12,901	13,379	25,681	28,822
Minority Interest	(814)	(813)	(1,700)	(1,694)
NET INCOME	19,304	27,946	31,509	32,968
Preferred Stock Dividend Requirements	58	58	115	115
EARNINGS APPLICABLE TO COMMON STOCK	$ 19,246	$ 27,888	$ 31,394	$ 32,853

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 135,660	$ 245,003	$ 359,907	$ (43,910)	$ 696,660
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(115)		(115)
TOTAL					666,545
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $333				(618)	(618)
Minimum Pension Liability, Net of Tax of $12,420				23,066	23,066
NET INCOME			32,968		32,968
TOTAL COMPREHENSIVE INCOME					55,416
JUNE 30, 2004	$ 135,660	$ 245,003	$ 362,760	$ (21,462)	$ 721,961
DECEMBER 31, 2004	$ 135,660	$ 245,003	$ 389,135	$ (1,180)	$ 768,618
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(115)		(115)
TOTAL					743,503
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,807				(5,212)	(5,212)
NET INCOME			31,509		31,509
TOTAL COMPREHENSIVE INCOME					26,297
JUNE 30, 2005	$ 135,660	$ 245,003	$ 395,529	$ (6,392)	$ 769,800

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,667,723	$ 1,663,161
Transmission	639,968	632,964
Distribution	1,133,748	1,114,480
General	435,127	427,910
Construction Work in Progress	70,161	48,852
Total	3,946,727	3,887,367
Accumulated Depreciation and Amortization	1,762,560	1,709,758
TOTAL - NET	2,184,167	2,177,609
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,047	4,049
Other Investments	4,628	4,628
TOTAL	8,675	8,677
CURRENT ASSETS		
Cash and Cash Equivalents	4,591	2,308
Other Cash Deposits	-	6,292
Advances to Affiliates	188,077	39,106
Accounts Receivable:		
Customers	39,842	39,042
Affiliated Companies	16,447	28,817
Miscellaneous	5,215	5,856
Allowance for Uncollectible Accounts	(5)	(45)
Fuel Inventory	44,260	45,793
Materials and Supplies	36,022	36,051
Risk Management Assets	7,456	25,379
Regulatory Asset for Under-Recovered Fuel Costs	25,762	4,687
Margin Deposits	1,341	3,419
Prepayments and Other	17,048	18,331
TOTAL	386,056	255,036
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	21,903	18,000
Unamortized Loss on Reacquired Debt	19,369	20,765
Other	13,234	16,350
Long-term Risk Management Assets	9,095	17,179

Prepaid Pension Obligations	80,599	81,132
Deferred Property Taxes	19,047	-
Deferred Charges	46,159	51,561
TOTAL	209,406	204,987
TOTAL ASSETS	$ 2,788,304	$ 2,646,309

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
June 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $18 par value per share:		
Authorized - 7,600,000 shares		
Outstanding - 7,536,640 shares	$ 135,660	$ 135,660
Paid-in Capital	245,003	245,003
Retained Earnings	395,529	389,135
Accumulated Other Comprehensive Income (Loss)	(6,392)	(1,180)
Total Common Shareholder's Equity	769,800	768,618
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholders' Equity	774,500	773,318
Long-term Debt:		
Nonaffiliated	690,546	545,395
Affiliated	50,000	50,000
Total Long-term Debt	740,546	595,395
TOTAL	1,515,046	1,368,713
Minority Interest	1,953	1,125
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	209,954	209,974
Accounts Payable:		
General	56,582	40,001
Affiliated Companies	42,099	33,285
Customer Deposits	30,082	30,550
Taxes Accrued	46,433	45,474
Interest Accrued	12,049	12,509
Risk Management Liabilities	8,038	18,607
Obligations Under Capital Leases	4,781	3,692
Regulatory Liability for Over-Recovered Fuel Costs	6,076	9,891
Other	34,419	33,417
TOTAL	450,513	437,400
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	401,158	399,756
Long-term Risk Management Liabilities	5,328	9,128
Reclamation Reserve	-	7,624
Regulatory Liabilities:		
Asset Removal Costs	251,382	249,892
Deferred Investment Tax Credits	33,392	35,539
Excess Earnings	3,167	3,167

Other	6,667	21,320
Asset Retirement Obligations	33,461	27,361
Obligations Under Capital Leases	33,578	30,854
Deferred Credits and Other	52,659	54,430
TOTAL	820,792	839,071
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,788,304	$ 2,646,309

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 31,509	$ 32,968
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	65,650	63,264
Deferred Property Taxes	(19,047)	(19,375)
Deferred Income Taxes	176	(4,519)
Deferred Investment Tax Credits	(2,147)	(2,163)
Mark-to-Market of Risk Management Contracts	13,031	12,181
Over/Under Fuel Recovery	(24,890)	8,598
Change in Other Noncurrent Assets	6,326	(12,889)
Change in Other Noncurrent Liabilities	(20,982)	3,747
Changes in Components of Working Capital:		
Accounts Receivable, Net	12,171	(4,473)
Fuel, Materials and Supplies	1,562	2,110
Accounts Payable	27,772	3,352
Taxes Accrued	959	46,489
Customer Deposits	(468)	2,471
Interest Accrued	(460)	(5,004)
Other Current Assets	3,361	5,727
Other Current Liabilities	3,616	(19,518)
Net Cash Flows From Operating Activities	98,139	112,966
INVESTING ACTIVITIES		
Construction Expenditures	(72,150)	(45,879)
Change in Other Cash Deposits, Net	6,292	803
Proceeds from Sale of Assets	108	2,316
Net Cash Flows Used For Investing Activities	(65,750)	(42,760)
FINANCING ACTIVITIES		
Issuance of Long-term Debt	148,895	92,441
Retirement of Long-term Debt	(4,915)	(220,000)
Changes in Advances to/from Affiliates, Net	(148,971)	93,394
Dividends Paid on Common Stock	(25,000)	(30,000)
Dividends Paid on Cumulative Preferred Stock	(115)	(115)
Net Cash Flows Used For Financing Activities	(30,106)	(64,280)
Net Increase in Cash and Cash Equivalents	2,283	5,926
Cash and Cash Equivalents at Beginning of Period	2,308	5,676
Cash and Cash Equivalents at End of Period	$ 4,591	$ 11,602

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $22,279,000 and $29,841,000 and for income taxes was $35,969,000 and $3,220,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions were $2,035,000 and $16,379,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(2,377,000) and $164,000 in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

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

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

CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to financial statements that follow are a combined presentation for AEP's registrant subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Significant Accounting Matters	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
4.	Customer Choice and Industry Restructuring	CSPCo, OPCo, TCC, TNC
5.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
7.	Acquisitions, Dispositions and Assets Held for Sale	CSPCo, TCC
8.	Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Income Taxes	APCo, CSPCo, OPCo, PSO, TCC
11.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Company-wide Staffing and Budget Review	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2004 Annual Report as incorporated in and filed with the 2004 Form 10-K.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments which are necessary for a fair presentation of the results of operations for interim periods.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the capitalization section. The components of Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries are shown in the following table:

Components	June 30, 2005	December 31, 2004
	(in thousands)	
Cash Flow Hedges:		
APCo	$ (23,206)	$ (9,324)
CSPCo	(2,892)	1,393
I&M	(8,768)	(4,076)
KPCo	(1,143)	813
OPCo	(5,858)	1,241
PSO	(1,083)	400
SWEPCo	(6,032)	(820)
TCC	(357)	657
TNC	(154)	285
Minimum Pension Liability:		
APCo	$ (72,348)	$ (72,348)
CSPCo	(62,209)	(62,209)
I&M	(41,175)	(41,175)
KPCo	(9,588)	(9,588)
OPCo	(75,505)	(75,505)
PSO	(325)	(325)
SWEPCo	(360)	(360)
TCC	(4,816)	(4,816)
TNC	(413)	(413)

Accounting for Asset Retirement Obligations (ARO)

All of AEP's Registrant Subsidiaries implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life.

The following is a reconciliation of beginning and ending aggregate carrying amounts of ARO by Registrant Subsidiary:

	Balance at January 1, 2005	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at June 30, 2005
			(in millions)			
AEGCo (a)	$ 1.2	$ 0.1	$ -	$ -	$ -	$ 1.3
APCo (a)	24.6	1.0	-	-	-	25.6
CSPCo (a)	11.6	0.4	-	-	-	12.0
I&M (b)	711.8	23.6	-	-	-	735.4
OPCo (a)	45.6	1.8	-	-	-	47.4
SWEPCo (c)	27.4	0.6	8.8	(0.1)	-	36.7
TCC (d)	248.9	7.5	-	(256.4)	-	-

(a) Consists of ARO related to ash ponds.
(b) Consists of ARO related to ash ponds ($1.3 million at June 30, 2005) and nuclear decommissioning costs for the Cook Plant ($734.1 million at June 30, 2005).
(c) Consists of ARO related to Sabine Mining Company and Dolet Hills Lignite Company, LLC (Dolet Hills). The current portion of Dolet Hills ARO, totaling $3.2 million, is included in Other in the Current Liabilities section of SWEPCo’s June 30, 2005 Condensed Consolidated Balance Sheet.
(d) The ARO for TCC’s share of STP was included in Liabilities Held for Sale - Texas Generation Plants in TCC’s Consolidated Balance Sheet at December 31, 2004 and was subsequently transferred to the buyer with the sale in the second quarter of 2005 (see “Texas Plants - South Texas Project” section of Note 7).

Accretion expense is included in Other Operation expense in the respective income statements of the individua Registrant Subsidiaries.

As of June 30, 2005 and December 31, 2004, the fair value of assets that are legally restricted for purposes of settling I&M’s nuclear decommissioning liabilities totaled $832 million and $791 million, respectively, and were recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M’s Condensed Consolidated Balance Sheets.

Reclassification

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2005 that we have determined relate to our operations.

SFAS 123 (revised 2004) “Share-Based Payment” (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, “Share-Based Payment.” SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees.” The statement is effective as of the first annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially applying the statement.

The Registrant Subsidiaries will implement SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. The Registrant Subsidiaries do not expect implementation of SFAS 123R to materially affect their results of operations, cash flows or financial condition.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. The Registrant Subsidiaries will apply the principles of SAB 107 in conjunction with their adoption of SFAS 123R.

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

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and FASB Statement No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that does not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005 with early implementation permitted for accounting changes and corrections of errors made in fiscal years beginning after the date this statement is issued. SFAS 154 is effective for the Registrant Subsidiaries beginning January 1, 2006 and will be applied when applicable.

FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143 "Accounting for Asset Retirement Obligations." FIN 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

The Registrant Subsidiaries will implement FIN 47 during the fourth quarter for the fiscal year ending December 31, 2005. Implementation will require a potential adjustment for the cumulative effect for any nonregulated operations of initially applying FIN 47 to be recorded as a change in accounting principle, disclosure of pro forma liabilities and asset retirement obligations, and other additional disclosures. The Registrant Subsidiaries have not completed their evaluation of any potential impact to their results of operations, cash flows or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, management cannot determine the impact on the reporting of operations that may result from any such future changes. The FASB is currently working on several projects including accounting for uncertain tax positions, business combinations, liabilities and equity, revenue recognition, pension plans, fair value measurements and related tax impacts. Management also expects to see more FASB projects as a result of the FASB's desire to converge

International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

As discussed in the 2004 Annual Report, certain AEP subsidiaries are involved in rate and regulatory proceedings at the FERC and at state commissions. The Rate Matters note within the 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending. The following sections discuss current activities and update the 2004 Annual Report.

APCo Virginia Environmental and Reliability Costs - Affecting APCo

In April 2004, the Virginia Electric Restructuring Act was amended to include a provision which permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred 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. Approximately $14 million of the amount requested represents incremental E&R costs for the twelve months ended June 30, 2005 and $48 million represents projected incremental E&R costs to be incurred for the twelve months ending June 30, 2006. The $62 million request relates to 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, recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kilovolt transmission line construction and other incremental T&D system reliability costs.

Through June 30, 2005, APCo has deferred for future recovery $9 million consisting of the $14 million of incremental E&R costs incurred to date, partially offset by $2 million of equity carrying costs not recognizable until collected and $3 million of capitalized interest recorded on the incremental E&R capital investments. APCo requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. If approved, the recovery factor will be applied as a 9.18% surcharge to customer bills. APCo proposed to practice under/over-recovery accounting for the difference between the actual incremental costs incurred and the cost recovered.

On July 14, 2005, the Virginia SCC issued an order that established a procedural schedule in APCo's proceeding including a public hearing on February 7, 2006. The order provided that no portion of APCo's application should become effective pending further decision of the Virginia SCC. Each party to the proceeding may file legal arguments on or before September 6, 2005, on whether and, under what circumstances, the Virginia SCC has the authority to make effective, on an interim basis subject to refund, any portion of APCo's requested rate change. Management is unable to predict the final outcome of this proceeding. If the Virginia SCC denies recovery of net incremental amounts deferred of $9 million, it would adversely affect APCo's future results of operations and cash flows.

APCo West Virginia Rate Case - Affecting APCo

On July 1, 2005, APCo and WPCo formally notified the Public Service Commission of West Virginia of their intent to file a joint general rate case seeking increases in retail rates in the third quarter of 2005. The filing will include, among other things, a request to reinstate the suspended expanded fuel, net energy and purchased power clause and to provide for scheduled rate recovery of significant environmental and transmission expenditures. As of June 30, 2005 and December 31, 2004, APCo had $52 million of previously over-recovered fuel, net energy and purchased power costs recorded in Regulatory Liabilities Over-recovery of Fuel Cost on its Condensed Consolidated Balance Sheets. Management is unable to predict the ultimate effect of this filing on revenues, results of operations, cash flows and financial condition.

I&M Indiana Settlement Agreement - Affecting I&M

In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005 and filed the agreement with the IURC on March 14, 2005. The IURC approved the agreement on June 1, 2005.

The approved settlement caps fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total capped fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month. In accordance with the agreement, the October 2005 through March 2006 factor will be adjusted for the delayed implementation of the 2005 factor.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), the ratio of the sum of fuel and one half maintenance expenses incurred by the pool members to the total kilowatt-hours of net generation, excluding I&M, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total actual fuel costs (except during a Cook Plant outage of greater than 60 days) are under the cap prices, the excess will be credited to customers over the next two fuel adjustment clause filings. Under the settlement, fuel costs in excess of the cap price cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

The settlement agreement also caps base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this cap period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M’s control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

Our cumulative under recovery for March 2004 through June 2005 recorded as fuel expense is $7 million. If future fuel cost per KWH through June 30, 2007 continue to exceed the caps, or if the base rate cap precludes I&M from seeking timely rate increases to recover increases in its cost of service through June 30, 2007, I&M’s future results of operations and cash flows would be adversely affected.

I&M Michigan Fuel Recovery Plan - Affecting I&M

In September 2004, I&M filed its 2005 Power Supply Cost Recovery (PSCR) Plan, with the requested PSCR factors implemented pursuant to the statute effective with January 2005 billings, replacing the 2004 factors. On March 29, 2005, the Michigan Public Service Commission (MPSC) issued an order approving an agreement authorizing I&M’s proposed 2005 PSCR Plan factors.

On March 31, 2005, I&M filed its 2004 PSCR Reconciliation seeking recovery of approximately $2 million of unrecovered PSCR fuel costs and interest proposed to be recovered through the application of customer bill surcharges during October 2005 through December 2005.

On April 28, 2005, the MPSC issued an Opinion and Order approving I&M’s proposed 2004 PSCR factors as billed and finding in favor of I&M on all issues, including the proposed treatment of net SO_2 and NO_x credits.

PSO Fuel and Purchased Power - Affecting PSO

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. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. The OCC has indicated that PSO will not be allowed recovery of the $42 million until the margin issue discussed below is decided. If the OCC denies recovery of any portion of the $42 million under-recovery of fuel costs, PSO's future results of operations and cash flows would be adversely affected.

In the review of PSO's 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and that the AEP West companies should have been allocated greater margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. On July 25, 2005, the OCC Staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East and AEP West companies. Their overall recommendations related to the allocation would result in an increase in off-system sales margins and thus, a reduction to 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 PSO will defend vigorously its position. Accordingly, PSO has not recorded a provision for the off-system sales margins issue. If the OCC reduces recovery of any portion of the fuel costs as a result of the off-system sales margins issue, PSO's future results of operations and cash flows would be adversely affected.

In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power practices for 2003. On June 10, 2005, the OCC decided to have its staff conduct that review. Management is unable to predict the ultimate effect of these proceedings on PSO's revenues, results of operations, cash flows and financial condition.

PSO Lawton Power Supply Agreement - Affecting PSO

On November 26, 2003, pursuant to an application by Lawton Cogeneration Incorporated seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs. The order did not approve recovery by PSO of the resultant purchased power costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court. In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Oklahoma Supreme Court issued a decision on June 21, 2005 affirming portions of the OCC's order and remanding certain provisions. The Court affirmed the OCC's finding that Lawton established a legally enforceable obligation and ruled that it was within the OCC's discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO's avoided energy cost. The decision also authorizes the OCC to revisit its determination of PSO's avoided capacity costs. Management is unable to predict the final outcome of the remand, however, if the OCC were to deny recovery of the full cost of the Agreement, it would adversely affect future PSO's results of operations and cash flows.

Upon resolution of the litigation, management will review any resultant transaction to determine if it can be accounted for as a purchased power transaction or whether it will be accounted for as a lease or as a generating plant asset on the balance sheet under FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities."

PSO Rate Review - Affecting PSO

PSO has been involved in a commission staff-initiated base rate review before the OCC which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. 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, allowing for the implementation of new base rates in June 2005.

SWEPCo Louisiana Fuel Audit - Affecting SWEPCo

SWEPCo, the District Court Complaintiffs and the Louisiana Public Service Commission (LPSC) Staff have reached an uncontested settlement in the SWEPCo Louisiana fuel audit, which will result in SWEPCo refunding approximately $18 thousand for the 1999 through 2002 audit period. A settlement hearing was held on June 22, 2005, and the ALJ is expected to render her report to the LPSC. The LPSC, through an oral motion, approved the settlement at its July 22, 2005 meeting. SWEPCo intends to seek the concurrence of the Caddo District Court regarding the pending suit alleging past over-recoveries of fuel costs back to 1975. If the Court does not agree with LPSC Staff recommendations, it could have an adverse effect on SWEPCo's future results of operations and cash flows.

TCC Rate Case - Affecting TCC

TCC has an on-going T&D rate review before the PUCT. In that rate review, the PUCT has decided all issues except the amount of affiliate expenses to include in revenue requirements. Through an oral ruling, the PUCT approved the nonunanimous settlement filed in June 2005 that provides for an $11 million disallowance of affiliate expenses which, when combined with the previous decisions, results in a total reduction in TCC's annual base rates of $9 million. A draft final order has been issued reflecting the $9 million reduction in TCC's annual base rates. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. It is anticipated that the PUCT will approve the final written order at its August 2005 open meeting. If the final written order differs from the draft order, it could impact TCC's projected annual pretax earnings effect.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal - Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, Texas Court of Appeals issued a decision reversing the District Court on the loss of load issue but otherwise affirming its decision. The amount of unaccounted for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million and is the responsibility of AEP.

Unbundled Cost of Service (UCOS) Appeal - Affecting TCC

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new T&D rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The District Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable T&D rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale of AEP's former affiliated REPs is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on TCC's future results of operations and cash flows.

Hold Harmless Proceeding - Affecting APCo, CSPCo, I&M, KPCo and OPCo

In a July 2002 order conditionally accepting AEP's choice to join PJM, the FERC directed AEP, ComEd, Midwest Independent Transmission System Operator (MISO) and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO.

In July 2004, AEP and PJM filed jointly with the FERC a hold-harmless proposal. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. The Michigan and Wisconsin utilities presented studies that show estimated adverse effects to utilities in the two states in the range of $60 million to $70 million over the term of the agreement for AEP and ComEd. A supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP and ComEd presented studies that show no adverse effects to the Michigan and Wisconsin utilities. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250 thousand that was approved by the FERC on March 7, 2005. On April 25, 2005, AEP and International Transmission Company in Michigan filed a settlement that resolves all hold-harmless issues for a one-time payment of $120 thousand that was approved by the FERC on June 24, 2005. On May 19, 2005, AEP and all remaining Michigan companies filed a settlement that resolves all hold-harmless issues for a one-time payment of approximately $2 million which was approved by the FERC on June 24, 2005.

The payment to the Michigan utilities will be deferred, as was the Wisconsin payment, as a PJM integration cost to be amortized over 15 years and recovery will be sought in future retail rate filings. Management believes that it is probable that these payments will ultimately be recovered from retail and wholesale customers. If the AEP East companies cannot recover these amortizations on a timely basis in their retail base rates, their future results of operations and cash flows will be adversely affected.

FERC Order on Regional Through and Out Rates - Affecting APCo, CSPCo, I&M, KPCo and OPCo

A load-based transitional transmission rate mechanism called 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. Intervenors in that proceeding are objecting to the SECA rates and AEP's method of determining those rates. Management is unable to determine the probable outcome of the FERC's SECA rate proceeding. SECA revenues by Registrant Subsidiary are shown in the following table:

Company	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005	December 2004
		(in millions)	
APCo	$ 10.4	$ 19.0	$ 3.5
CSPCo	5.3	9.6	2.0
I&M	5.9	10.8	2.3
KPCo	2.5	4.5	0.8
OPCo	7.4	13.5	2.8

In a March 31, 2005 FERC filing, AEP 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 and municipal, 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 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 proposed 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. This investigation provides AEP an opportunity to propose and support a new PJM rate regime that could mitigate losses from the elimination of T&O transmission rates and the discontinuance of the SECA rate collections.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, 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, management is 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 AEP's 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) FERC does not approve a new rate within PJM or within the PJM and MISO Regions that compensates for AEP's T&O revenue losses, the AEP East companies' future results of operations, cash flows and financial condition would be adversely affected.

RTO Formation/Integration - Affecting APCo, CSPCo, I&M, KPCo and OPCo

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs incurred to originally form a new

RTO (the Alliance) and subsequently to join an existing RTO (PJM). In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The FERC approved AEP's application. The formation and integration costs included in AEP's application by company follows:

Company	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)	
APCo	$ 4.8	$ 5.1
CSPCo	2.0	2.2
I&M	3.8	3.8
KPCo	1.1	1.1
OPCo	5.5	5.7

In January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years (the latter, consistent with a March 8, 2005 requested rate recovery period discussed below). The total amortization related to such costs was $1 million and $2 million in the second quarter and first half of 2005, respectively. As of June 30, 2005, the AEP East Companies have $34 million of deferred unamortized RTO formation/integration costs.

Company	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)	
APCo	$ 5.0	$ 4.7
CSPCo	2.1	2.0
I&M	3.9	3.5
KPCo	1.2	1.0
OPCo	5.8	5.2

On March 8, 2005, AEP and two other utilities jointly filed a request with the FERC to recover the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. The FERC responded to the March 8, 2005 filing in an order on May 6, 2005 denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a Compliance Filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the Compliance Filing on May 27, 2005. On June 6, 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including to the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). AEP's rehearing request remains pending. At this time, management is unable to predict the likelihood of a favorable rehearing result.

On March 31, 2005, AEP also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed above). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of AEP's deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs).

The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

Until the AEP East Companies can adjust their retail rates to recover the amortization of both deferred costs, results of operations and cash flows will be adversely affected by the amortizations. If the FERC were to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs not billed by PJM, it would have an adverse impact on the AEP East companies' future results of operations and cash flows.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Certain AEP subsidiaries are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in the 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring and update the 2004 Annual Report.

OHIO RESTRUCTURING - Affecting CSPCo and OPCo

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 additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues. 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 were increased by $14 million for CSPCo and $40 million for OPCo in the first half of 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo relate to 2004 environmental carrying costs and RTO costs.

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. If the RSP order was determined to be illegal under the Restructuring Legislation, as contended by the two intervenors, it would have an adverse effect on results of operations, cash flow and possibly financial condition. Although management believes that the RSP plan is legal and intends to defend vigorously the PUCO's order, management cannot predict the ultimate outcome of the pending litigation.

The PUCO's order in the RSP require CSPCo and OPCo to allot a combined total of $14 million of previously provided for unused CSPCo shopping incentives to benefit their low-income customers and economic development programs over the three-year period ending December 31, 2008. In a March 23, 2005 rehearing order, the PUCO clarified that the Ohio companies have a regulatory liability of only $14 million of unused shopping incentives. Through June 30, 2005, CSPCo has credited $18 million of unused shopping incentives against its transition regulatory asset. Therefore, CSPCo could cease applying unused credits to reduce its recoverable transition regulatory asset and reverse any excess unused shopping incentives. Assuming that the $14 million regulatory liability is allocated equally to CSPCo and OPCo, in the second quarter of 2005, CSPCo increased its recoverable transition regulatory asset by $18 million, transferred $7 million to a regulatory liability and credited the remaining $11 million to pretax earnings and OPCo recorded a regulatory liability of $7 million which it charged to pretax earnings.

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through June 30, 2005, CSPCo and OPCo incurred $41 million and $42 million, respectively, of such costs, and accordingly, CSPCo and OPCo deferred $21 million and $22 million, respectively, of such costs for probable future recovery in distribution rates.

Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. Management believes that the deferred customer choice implementation costs were prudently incurred and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on CSPCo's and OPCo's future results of operations and cash flows.

TEXAS RESTRUCTURING - Affecting TCC and TNC

The stranded cost recovery process in Texas continues with the principal remaining component of the process being 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. 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, including unrecorded equity carrying costs and future unrecorded carrying costs through September 2005. This filing does not include a deduction for 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. Although it was determined that it was probable that the PUCT would make this adjustment in TCC's proceeding, management does not believe the adjustment is appropriate and will litigate the issue, if necessary. As a result, the filing was not reduced by the $238 million. The PUCT hearing is scheduled to begin on September 26, 2005. It is anticipated that the PUCT will issue a final order in the fourth quarter of 2005.

The Components of TCC's Recorded Net True-up Regulatory Asset (inclusive of provisions) as of June 30, 2005 and December 31, 2004 are:

	TCC	
	June 30, 2005	December 31, 2004
	(in millions)	
Stranded Generation Plant Costs	$ 887	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(3)	(10)
Net Stranded Generation Costs	1,133	1,136
Carrying Costs on Stranded Generation Plant Costs	215	225
Net Stranded Generation Costs Designated for Securitization	1,348	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	102	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(209)	(212)
Net Other Recoverable True-up Amounts	315	287
Total Recorded Net True-up Regulatory Asset	$ 1,663	$ 1,648

The Components of TNC's Net True-up Regulatory Liability as of June 30, 2005 and December 31, 2004 are:

	TNC	
	June 30, 2005	December 31, 2004

		(in millions)	
Retail Clawback	$	(14)	$ (14)
Deferred Over-recovered Fuel Balance		(5)	(4)
Total Recorded Net True-up Regulatory Liability	$	(19)	$ (18)

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that net stranded generation costs should be reduced by the present value of deferred investment tax credits (ITC) and excess deferred federal income taxes applicable to generating assets. The nonaffiliated utility testified in its True-up Proceeding that acceleration of the sharing of deferred ITC with customers may be a violation of the Internal Revenue Code's normalization provisions. Management agrees with the nonaffiliated utility that the PUCT's acceleration of deferred ITC and excess deferred federal income taxes may be a violation of the normalization provisions. As a result, management has not included as a reduction of its net stranded generation costs the present value of TCC's generation-related deferred ITC of $70 million and the present value of excess deferred federal income taxes of $6 million in its true-up filing. Such amounts also are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table since to do so may be a normalization violation. The Internal Revenue Service (IRS) has issued proposed regulations that would make an exception to the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS has not issued final regulations, TCC filed a request for a private letter ruling from the IRS on June 28, 2005 to determine whether the PUCT's action would result in a normalization violation. A normalization violation could result in the repayment of TCC's accumulated deferred ITC on all property, not just generation property, which approximates $106 million as of June 30, 2005 and a loss of the ability to elect accelerated tax depreciation in the future. Management is unable to predict how the IRS will rule on the private letter ruling request and whether any PUCT order will adversely affect TCC's future results of operations and cash flows.

TCC Fuel Reconciliation

On April 14, 2005, the PUCT ruled that specific energy-only purchased power contracts included a capacity component, which is not recoverable in fuel rates. As a result of this decision, in the first quarter of 2005, TCC recorded a provision for over-recovered fuel of $3 million, inclusive of interest. Reflecting all of the decisions in the final order and the resultant provisions for refund, the deferred over-recovery balance was $209 million as of June 30, 2005, including accrued interest. TCC has filed a motion for rehearing on several items which was denied by operation of law on July 18, 2005. TCC will appeal the PUCT's decision to the courts in August 2005.

TCC Carrying Costs on Net True-up Regulatory Assets

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 the nonaffiliated utility's securitization proceeding discussed above, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. In the first half of 2005, TCC accrued carrying costs of $42 million which were partially offset by a first quarter adjustment of $27 million based on this order. The net increase of $15 million in carrying costs is included in Carrying Costs on Stranded Cost Recovery on TCC's accompanying Condensed Consolidated Statements of Operations in the first half of 2005 inclusive of $21 million of carrying costs accrued in the second quarter of 2005.

In an April 2005 open meeting regarding another nonaffiliated utility's True-up Proceeding, the PUCT determined that the filed cost of debt did not establish a Weighted Average Cost of Capital (WACC) rate or an embedded debt rate because that utility's Unbundled Cost of Service (UCOS) case was based on a settlement that did not specifically address the debt rate. As a result, the other utility was required to use a lower rate to compute its carrying costs than its filed UCOS rate. With this precedent, TCC anticipates that it will be required to address the WACC issue. Although TCC's UCOS case was also settled, TCC's facts and circumstances differ from those of the nonaffiliated utility in that TCC's settlement included a WACC rate and the UCOS order approving the settlement included sufficient other information to determine the embedded debt rate in the settlement. Management, however, is unable to determine the probable outcome of this matter when or if it is adjudicated in TCC's True-up Proceeding. If the PUCT ultimately determines that a similar lower cost of debt 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 would have an adverse impact on future results of operations and cash flows. Through the second quarter of 2005, such reversal would approximate $60 million, of which $9 million would apply to amounts accrued in 2005 based upon TCC's weighted cost of debt in its 2001 excess earnings report.

Through June 30, 2005, TCC has computed carrying costs of $483 million, of which $302 million was recognized as income in 2004 and applied to years prior to 2005. Approximately $42 million was recognized as income in the first half of 2005 before the $27 million offsetting adjustment discussed above. The remaining equity component of the carrying costs of $166 million through June 30, 2005 will be recognized in income as collected.

TCC Unrefunded Excess Earnings

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. In the first half of 2005, TCC refunded an additional $7 million reducing its unrefunded excess earnings to $3 million. On July 15, 2005, the PUCT approved a preliminary order in the TCC true-up that ordered TCC to cease refunding excess earnings at the end of July 2005. The unrefunded balance of excess earnings, as of the end of July 2005, is estimated to be approximately $1 million and will be credited to the balance of stranded costs.

TCC True-up Proceeding

As discussed earlier, TCC made its true-up filing requesting $2.4 billion of stranded costs. Hearings are scheduled to start on September 26, 2005 and an order is projected to be issued during the fourth quarter of 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 (CTC) in the regulated T&D rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

The nonaffiliated utility's March 2005 order referred to above also provided for the present value of the cost free capital benefits of ADFIT associated with stranded generation costs to be offset against other recoverable true-up amounts when establishing the CTC. TCC estimates its present value ADFIT benefit to be $211 million based on its current net true-up regulatory asset. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT in the nonaffiliated utility's order and determined that the projected cash flows from the transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding.

Management believes that TCC's filed $2.4 billion request for recovery of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation and that TCC's $1.7 billion recorded net true-up regulatory asset, inclusive of carrying costs at June 30, 2005, is probable of recovery at this time. However , management anticipates that other parties will contend in TCC's proceeding that material amounts of TCC's 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 TCC's interpretation and application of the Texas Restructuring

Legislation and TCC's 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 an adverse effect on TCC's future results of operations, cash flows and possibly financial condition.

TNC True-Up Proceeding

In May 2005, the PUCT issued a favorable order, adopting the ALJ's recommendation regarding the post-reconciliation period off-system sales margins, but did not adopt his excess earnings recommendation. The PUCT stated that excess earnings would be addressed in the CTC filing scheduled to be filed in the third quarter of 2005. Based upon the ruling regarding off-system sales margins, TNC adjusted its deferred over-recovered fuel balance during the second quarter of 2005.

In 2004, TNC appealed to the state and federal courts the PUCT's order in its final fuel reconciliation covering the period from July 2000 through December 31, 2001 in which the PUCT disallowed approximately $30 million of fuel costs. In March 2005, the ALJ made certain recommendations regarding the deferred fuel balance resulting in an additional provision for refund of $1 million, which results in an over-recovery amount of $5 million. TNC will pursue vigorously its appeals, but cannot predict their outcome, however, the result of these appeals could affect the TNC true-up order issued by the PUCT in May 2005 discussed above.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within the 2004 Annual Report, certain Registrant Subsidiaries continue to be involved in various legal matters. The 2004 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since their disclosure in the 2004 Annual Report. The matters discussed in the 2004 Annual Report without significant changes in status since year-end include, but are not limited to, (1) carbon dioxide public nuisance claims, (2) nuclear matters, (3) construction and commitments, (4) potential uninsured losses and (5) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in the 2004 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

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 AEP 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 the generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing is underway and closing arguments will be heard on September 22, 2005.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

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 are 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 complaint 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 in January 2005 and to the Federal EPA's complaint in July 2005, denying the allegations and stating its defenses.

In August 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A settlement between Ohio Edison, the Federal EPA and other parties to the litigation will avoid further litigation and result in expenditures at its plant.

Other utility enforcement actions and current regulatory activities are discussed in detail in the Commitments and Contingencies note in the 2004 Annual Report. However, since the issuance of the August 2003 decision against Ohio Edison, several other courts have considered the issues of what constitutes "routine maintenance, repair, and replacement" for utility units, and whether increased hours of operation are the measure of an emissions increase, and each court has reached a conclusion that differs markedly from the decision in the Ohio Edison case. These decisions include the District Court opinion in the Duke Energy case issued later in August 2003, the District Court opinion in Alabama Power issued on June 3, 2005, and the Fourth Circuit Court of Appeals opinion affirming the dismissal of all claims against Duke Energy issued on June 15, 2005. In addition, on June 10, 2005, the Administrator of the Federal EPA rejected all of the petitions for reconsideration of the October 2003 "equipment replacement provision" rule that defines "routine replacement" under the new source review program to include the same types of activities challenged in the pending enforcement actions. Management therefore believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in the AEP case also vary widely from plant to plant.

In June 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which the AEP subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in the AEP case and other related cases. On June 24, 2005, the United States Court of Appeals for the D.C. Circuit issued a decision affirming in part the new source review reform regulations adopted by the Federal EPA in December of 2002. The court upheld the Federal EPA's decision to apply an actual-to-future actual emissions test, utilizing a five-year look back period to establish actual baseline emissions for utilities and a ten-year period for other sources, and excluding increased emissions unrelated to a physical change from the projected emissions, including 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. The Court expressed no opinion on the conclusion reached by the Duke Energy court, and found that such issues could be better addressed in a specific factual context.

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

SWEPCo Notice of Enforcement and Notice of Citizen Suit - Affecting SWEPCo

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 SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. 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. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. 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 $228,312 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.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director’s Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

OPERATIONAL

TEM Litigation - Affecting OPCo

AEP has 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 AEP. AEP has 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 has also 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 OPCo separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. OPCo alleges that TEM has breached the PPA, and is seeking a determination of OPCo’s rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of OPCo’s breaches. If the PPA is deemed terminated or found to be unenforceable by the court, OPCo could be adversely affected to the extent it is unable to find other purchasers of the power with similar contractual terms and to the extent OPCo does not fully recover claimed termination value damages from TEM. However, OPCo has entered an agreement with an affiliate that eliminates OPCo’s market exposure related to the PPA. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the “creation of protocols” was not subject to arbitration, but did not rule upon the merits of TEM’s claim that the PPA is not enforceable. On January 21, 2005, the District Court granted OPCo partial summary judgment on this issue, holding that the absences of operating protocols does not prevent enforcement of the PPA.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the “Commercial Operations Date.” Despite OPCo’s prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo’s tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been 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 and a decision is pending.

Merger Litigation-Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

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 has filed a petition for review of this Initial Decision, which the SEC has granted. The SEC is reviewing the Initial Decision.

Enron Bankruptcy -Affecting APCo, CSPCo, I&M, KPCo and OPCo

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

Enron Bankruptcy - Commodity trading settlement disputes - In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. The AEP subsidiaries have asserted their right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. The parties are currently in nonbinding court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding court-sponsored mediation.

Enron Bankruptcy - Summary - The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Although management is unable to predict the outcome of these lawsuits it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

Texas Commercial Energy, LLP Lawsuit - Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003 against AEP and four of its subsidiaries, including TCC and TNC, certain nonaffiliated energy companies and ERCOT. 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. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, sought leave to intervene as plaintiffs asserting similar claims. In June 2004, the Court dismissed all claims against the AEP companies. TCE has 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. 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. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

Coal Transportation Dispute - Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, have disputed transportation costs for coal received between July 2000 and the present time. The joint plant has remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded provisions for possible loss in December 2004 and the first six months of 2005. The provisions were deferred as a regulatory asset under PSO's fuel mechanism and affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

6. GUARANTEES

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

Letters of Credit

Certain Registrant Subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs generally cover items such as insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At June 30, 2005, the maximum future payments of the LOCs include $44 million, $1 million, $51 million, $4 million and $43 million for CSPCo, I&M, OPCo, SWEPCo and TCC, respectively, with maturities ranging from November 2005 to April 2007. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $50 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At June 30, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

SWEPCo consolidates Sabine due to the application of FIN 46. SWEPCo does not have an ownership interest in Sabine.

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant Subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and the first six months of 2005, Registrant Subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary except for TCC. TCC sales agreements include indemnifications with a maximum exposure of $443 million related to the sale prices of its generation assets. The status of certain sales agreements is discussed in Note 7. There are no material liabilities recorded for any indemnifications.

Registrant Subsidiaries are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and for activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At June 30, 2005, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Maximum Potential Loss

Subsidiary	**(in millions)**
APCo	$ 6
CSPCo	2
I&M	4
KPCo	1
OPCo	5
PSO	4
SWEPCo	4
TCC	6
TNC	3

7. ACQUISITIONS, DISPOSITIONS AND ASSETS HELD FOR SALE

ACQUISITIONS

Public Service Enterprise Group (PSEG) Waterford Energy LLC (Affecting CSPCo)

In May 2005, CSPCo signed a purchase and sale agreement with PSEG Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio for $220 million. This transition is contingent on the receipt of required regulatory approval and is expected to close in the third quarter of 2005.

Monongahela Power Company (Affecting CSPCo)

In June 2005, the PUCO ordered us 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 of Monongahela Power's Ohio customer base and the assets that serve those customers to CSPCo for an estimated sales price of approximately $55 million. The sale price will be adjusted based on book values of the acquired assets and liabilities at the closing date. We anticipate the purchase, subject to regulatory approval, to close late in the fourth quarter of 2005.

DISPOSITIONS COMPLETED AND ANTICIPATED BEING COMPLETED DURING 2005

Texas Plants - Oklaunion Power Station

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. In May 2004, TCC received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. In June 2004 and September 2004, TCC entered into sales agreements with both of its nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements are currently being challenged in Dallas County, Texas State District Court by the unrelated party with which TCC entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale - Texas Generation Plants and Liabilities Held for Sale - Texas Generation Plants, respectively, in TCC's Condensed Consolidated Balance Sheets at June 30, 2005 and December 31, 2004. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of AEP's Power Pool which includes all of the generation facilities owned by the Registrant Subsidiaries.

Texas Plants - South Texas Project

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

The assets and liabilities of the TCC plants held for sale at June 30, 2005 and December 31, 2004 are as follows:

	Texas Plants	
	June 30, 2005	December 31, 2004
Assets:	(in millions)	
Other Current Assets	$ 2	$ 24
Property, Plant and Equipment, Net	44	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale - Texas Generation Plants	$ 46	$ 628
Liabilities:		
Regulatory Liabilities	$ 1	$ 1
Asset Retirement Obligations	-	249

Total Liabilities Held for Sale - Texas Generation Plants	$ 1	$ 250

8. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2005 and 2004:

Three Months Ended June 30, 2005 and 2004	**Pension Plans**		**Other Postretirement Benefit Plans**	
	2005	**2004**	**2005**	**2004**
	(in millions)			
Service Cost	$ 23	$ 21	$ 10	$ 10
Interest Cost	56	56	26	29
Expected (Return) on Plan Assets	(78)	(72)	(22)	(20)
Amortization of Transition Obligation	-	1	7	7
Amortization of Net Actuarial Loss	14	4	7	9
Net Periodic Benefit Cost	$ 15	$ 10	$ 28	$ 35

Six Months Ended June 30, 2005 and 2004	**Pension Plans**		**Other Postretirement Benefit Plans**	
	2005	**2004**	**2005**	**2004**
	(in millions)			
Service Cost	$ 46	$ 43	$ 21	$ 20
Interest Cost	112	112	53	58
Expected (Return) on Plan Assets	(155)	(144)	(45)	(40)
Amortization of Transition Obligation	-	1	14	14
Amortization of Net Actuarial Loss	27	8	14	18
Net Periodic Benefit Cost	$ 30	$ 20	$ 57	$ 70

The following table provides the net periodic benefit cost (credit) for the plans by the following Registrant Subsidiaries for the three and six months ended June 30, 2005 and 2004:

Three Months Ended June 30, 2005 and 2004	**Pension Plans**		**Other Postretirement Benefit Plans**	
	2005	**2004**	**2005**	**2004**
	(in thousands)			
APCo	$ 1,848	$ 318	$ 5,147	$ 6,462
CSPCo	534	(407)	2,123	2,765
I&M	2,365	1,114	3,464	4,313
KPCo	376	144	571	742
OPCo	1,206	(105)	3,632	4,801
PSO	72	700	1,799	2,110
SWEPCo	364	901	1,765	2,101

TCC	(219)	746	1,935	2,535
TNC	41	338	846	1,073

Six Months Ended June 30, 2005 and 2004	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in thousands)			
APCo	$ 3,696	$ 636	$ 10,492	$ 12,924
CSPCo	1,068	(814)	4,345	5,530
I&M	4,730	2,228	7,095	8,626
KPCo	752	288	1,174	1,484
OPCo	2,412	(210)	7,459	9,602
PSO	144	1,400	3,668	4,220
SWEPCo	728	1,802	3,602	4,202
TCC	(438)	1,492	3,943	5,070
TNC	82	676	1,723	2,146

9. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, which is an electricity generation business. All of the registrants' other activities are insignificant. The registrant subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

10. INCOME TAXES

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In the second quarter of 2005, we reversed deferred state income tax liabilities that are not expected to reverse during the phase-out as follows:

Company	Amount (in thousands)
CSPCo	$ 15,104
OPCo	41,864
APCo	2,769
PSO	706
TCC	365

The reversal of deferred state income taxes for the Ohio companies was recorded as a regulatory liability pending ratemaking treatment in Ohio. The reversal of deferred state income taxes for APCO, PSO and TCC was recorded as a reduction to Income Taxes.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 is expected to be $1 million and $1 million for CSPCo and

OPCo, respectively.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0 % to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance polices; all of which will not have a material impact on future results of operations and cash flows.

11. FINANCING ACTIVITIES

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2005 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 200,000	4.95%	2015
APCo	Senior Unsecured Notes	150,000	4.40%	2010
APCo	Senior Unsecured Notes	250,000	5.00%	2017
OPCo	Installment Purchase Contracts	54,500	Variable	2029
OPCo	Installment Purchase Contracts	163,500	Variable	2028
PSO	Senior Unsecured Notes	75,000	4.70%	2011
SWEPCo	Senior Unsecured Notes	150,000	4.90%	2015
TCC	Installment Purchase Contracts	161,700	Variable	2030
TCC	Installment Purchase Contracts	120,265	Variable	2028

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

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Other Debt	$ 5	13.718%	2026
APCo	First Mortgage Bonds	50,000	8.00%	2005
APCo	First Mortgage Bonds	30,000	6.89%	2005
APCo	First Mortgage Bonds	45,000	8.00%	2025
APCo	Senior Unsecured Notes	450,000	4.80%	2005
OPCo	Installment Purchase Contracts	102,000	6.375%	2029
OPCo	Installment Purchase Contracts	80,000	Variable	2028
OPCo	Installment Purchase Contracts	36,000	Variable	2029
OPCo	Notes Payable	2,927	6.81%	2008
OPCo	Notes Payable	3,250	6.27%	2009
PSO	First Mortgage Bonds	50,000	6.50%	2005
SWEPCo	Notes Payable	3,415	4.47%	2011
SWEPCo	Notes Payable	1,500	Variable	2008
TCC	Senior Unsecured Notes	150,000	3.00%	2005
TCC	Senior Unsecured Notes	100,000	Variable	2005
TCC	Securitization Bonds	29,386	3.54%	2005

In addition to the transactions reported in the tables above, the following table lists intercompany issuances and retirements of debt due to AEP:

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)	(%)	
Issuances:				
APCo	Notes Payable	$ 100,000	4.708%	2010
Retirements:				
KPCo	Notes Payable	$ 20,000	6.501%	2006

Other Matters

On January 3, 2005, the following outstanding shares of preferred stock were redeemed:

Company	Series	Number of Shares Redeemed	Amount
			(in millions)
I&M	5.900%	132,000	$ 13
I&M	6.250%	192,500	19
I&M	6.875%	157,500	16
I&M	6.300%	132,450	13
OPCo	5.900%	50,000	5
			$ 66

Lines of Credit - AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2007 for short-term borrowings sufficient to fund the Utility Money Pool and the Nonutility Money Pool as well as its own requirements in an amount not to exceed $7.2 billion. The Utility Money Pool participants' money pool activity and corresponding SEC authorized limits for the six months ended June 30, 2005 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of June 30, 2005	SEC Authorized Short-Term Borrowing Limit
	(in thousands)					
AEGCo	$ 45,694	$ 9,305	$ 16,070	$ 4,803	$ (24,621)	$ 125,000
APCo	236,798	321,977	95,331	47,143	(176,692)	600,000
CSPCo	-	181,238	-	104,861	62,172	350,000
I&M	203,248	11,768	81,472	5,797	(143,126)	500,000
KPCo	3,386	35,779	2,307	17,596	12,647	200,000

OPCo	44,192	182,495	22,467	80,796	(11,528)	600,000
PSO	55,009	55,602	22,523	26,635	7,084	300,000
SWEPCo	221	188,215	221	42,793	188,077	350,000
TCC	320,508	120,937	152,714	49,350	(120,064)	600,000
TNC	-	75,045	-	49,428	63,665	250,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2005 were 3.43% and 1.63%, respectively. The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2005 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
	(in percentages)	
AEGCo	2.40	3.14
APCo	2.65	2.69
CSPCo	-	2.44
I&M	2.96	2.12
KPCo	2.96	2.42
OPCo	3.32	2.39
PSO	2.50	3.19
SWEPCo	3.21	2.54
TCC	2.91	2.12
TNC	-	2.65

12. COMPANY-WIDE STAFFING AND BUDGET REVIEW

The following table shows the severance benefits expense recorded in the second quarter of 2005 (primarily in Maintenance and Other Operation) resulting from a company-wide staffing and budget review, including the allocation of approximately $15.9 million of severance benefits expense associated with AEPSC employees among the Registrant Subsidiaries. AEGCo has no employees but receives allocated expenses.

Company	Amounts (in millions)
AEGCo	$ 0.2
APCo	3.9
CSPCo	2.3
I&M	4.0
KPCo	0.7
OPCo	3.4
PSO	1.2
SWEPCo	1.6
TCC	3.8
TNC	1.1

The above amounts are outstanding as of June 30, 2005 as current liabilities to AEPSC and to the respective registrant employees.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the management's discussion and analysis of Registrant Subsidiaries. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, and (iii) footnotes of each individual registrant. The Combined Management's Discussion and Analysis of Registrants Subsidiaries section of the 2004 Annual Report should be read in conjunction with this report.

Significant Factors

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called 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. Intervenors in that proceeding are objecting to the SECA rates and AEP's method of determining those rates. Management is unable to determine the probable outcome of the FERC's SECA rate proceeding. SECA revenues by Registrant Subsidiary are shown in the following table:

Company	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005	December 2004
		(in millions)	
APCo	$ 10.4	$ 19.0	$ 3.5
CSPCo	5.3	9.6	2.0
I&M	5.9	10.8	2.3
KPCo	2.5	4.5	0.8
OPCo	7.4	13.5	2.8

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 and municipal, 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 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 proposed 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. This investigation provides AEP an opportunity to propose and support a new PJM rate regime that could mitigate losses from the elimination of T&O transmission rates and the discontinuance of the SECA rate collections.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended

September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, 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) the FERC does not approve a new rate within PJM or within the PJM and MISO Regions that compensates for AEP's T&O revenue losses, future results of operations, cash flows and financial condition would be adversely affected.

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 additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues. 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 were increased by $14 million for CSPCo and $40 million for OPCo in the first half of 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo relate to 2004 environmental carrying costs and RTO costs.

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. If the RSP order was determined to be illegal under the Restructuring Legislation, as contended by the two intervenors, it would have an adverse effect on results of operations, cash flow and possibly financial condition. Although management believes that the RSP plan is legal and intends to defend vigorously the PUCO's order, management 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 $18 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover approximately $237 million in 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 Rate Stabilization Plans. In Phase 3, which begins when the plant enters commercial operation, the Ohio companies would recover the projected $1.2 billion cost of the plant and a return on the unrecovered cost over its operating life along with fuel, replacement power and operation and maintenance costs.

Litigation

Registrant Subsidiaries continue to be involved in various litigation matters as described in the “Significant Factors - Litigation” section of the Combined Management’s Discussion and Analysis of Registrant Subsidiaries in the 2004 Annual Report. The 2004 Annual Report should be read in conjunction with this report in order to understand other litigation matters that did not have significant changes in status since the issuance of the 2004 Annual Report, but may have an impact on 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 six months of 2005, that should be read in order to gain a full understanding of the current litigation include disclosure related to the Coal Transportation Dispute, Enron Bankruptcy and Potential Uninsured Losses.

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under “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 has filed a petition for review of this Initial Decision, which the SEC has granted. The SEC is reviewing the Initial Decision. Management believes adoption of the Energy Policy Act of 2005 may end litigation challenging the AEP/CSW merger.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four of its subsidiaries, including TCC and TNC, certain nonaffiliated energy companies and ERCOT. 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 TCC and TNC, 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 fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. In June 2004, the Court dismissed all claims against AEP and its subsidiaries. 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. 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. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

Environmental Matters

As discussed in the 2004 Annual Report, there are emerging environmental control requirements that management expects 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 sulfur dioxide (SO_2), nitrogen oxide (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 climatic change.

This discussion updates certain events occurring in 2005. You should also read the “Significant Factors - Environmental Matters” section within the Combined Management’s Discussion and Analysis of Registrant Subsidiaries in the 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) carbon dioxide public nuisance claims, (6) costs for spent nuclear fuel disposal and decommissioning, and (7) 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 is slightly revised from the proposed version released in January 2004, and 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 the Registrant Subsidiaries’ 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 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.

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 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, both the CAIR and CAMR 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 original rules described herein. If the final rules are remanded by the court, if states elect not to participate in the federal cap-and-trade programs, or if states elect to impose additional requirements on individual units that are already subject to the CAIR and/or the 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 Litigation

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

The 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 AEP 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 the generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing is underway and closing arguments will be heard on September 22, 2005.

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 are 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 in January 2005 and to the Federal EPA's complaint in July 2005, 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 test, utilizing a five-year look back period to establish actual baseline emissions for utilities and a ten-year period for other sources, and excluding increased emissions unrelated to a physical change from the projected emissions, including 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.

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

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 SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. 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. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. 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 $228,312 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.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director’s Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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

Emergency Release Reporting

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 will pay an immaterial civil penalty and 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 selective catalytic reduction system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

CONTROLS AND PROCEDURES

During the second quarter of 2005, management, including the principal executive officer and principal financial officer of each of AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2005, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2005 that materially affected, or is reasonably likely to materially affect, the Registrants' internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 5, *Commitments and Contingencies,* incorporated herein by reference.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended June 30, 2005 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
04/01/05 - 04/30/05	-	$ -	-	$ -
05/01/05 - 05/31/05	1	82.00	-	-
06/01/05 - 06/30/05	-	-	-	-
Total	1	$ 82.00	-	$ -

(a) OPCo repurchased 1 share of its 4.5% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.

On March 9, 2005, AEP announced the repurchase of 12.5 million shares of its outstanding common stock at an initial price of $34.63 per share. The share buyback plan was executed via an accelerated share repurchase (ASR) program. Under the ASR structure, AEP paid the counterparty $433 million upfront to buy back 12.5 million shares. On May 6, the counterparty paid AEP $6.5 million to settle the ASR. The positive settlement was due to the average price per share of $34.18 being lower than the initial price per share, as well as a rebate associated with the interest earned on the cash paid upfront by AEP to the counterparty.

Item 4. Submission of Matters to a Vote of Security Holders

AEP

The annual meeting of shareholders was held in Tulsa, Oklahoma, on April 26, 2005. The holders of shares entitled to vote at the meeting or their proxies cast votes at the meeting with respect to the following three matters, as indicated below:

1. Election of eleven directors to hold office until the next annual meeting and until their successors are duly elected. Each nominee for director received the votes of shareholders as follows:

	No. of Shares Voted For	No. of Shares Abstaining
E. R. Brooks	263,054,307	75,891,318
Donald M. Carlton	328,620,376	10,325,249
John P. DesBarres	328,782,449	10,163,176
Robert W. Fri	328,507,125	10,438,500
William R. Howell	329,883,269	9,062,356
Lester A. Hudson, Jr.	330,110,186	8,835,439
Michael G. Morris	330,275,243	8,670,382
Lionel L. Nowell, III	332,065,869	6,879,756
Richard L. Sandor	330,065,869	8,687,824
Donald G. Smith	330,181,157	8,764,468
Kathryn D. Sullivan	330,057,810	8,887,815

2. Ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm for 2005. The proposal was approved by a vote of the shareholders as follows:

Votes FOR	322,692,857
Votes AGAINST	12,412,630
Votes ABSTAINED	3,840,138
Broker NON-VOTES*	0

3. Approval of an amendment to the AEP System Long-term Incentive Plan. The proposal was approved by a vote of the shareholders as follows:

Votes FOR	249,862,019
Votes AGAINST	28,710,198
Votes ABSTAINED	8,059,517
Broker NON-VOTES*	52,313,891

*A non-vote occurs when a nominee holding shares for a beneficial owner votes on one proposal, but does not vote on another proposal because the nominee does not have discretionary voting power and has not received instructions from the beneficial owner.

APCo

The annual meeting of stockholders was held on April 26, 2005 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 13,499,500 votes were cast FOR each of the following eight persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

Carl L. English	Michael G. Morris
John B. Keane	Robert P. Powers
Holly K. Koeppel	Stephen P. Smith
Venita McCellon-Allen	Susan Tomasky

TCC

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 14, 2005, the following eight persons were elected directors to hold office for one year or until their successors are elected and qualify:

Carl L. English	Michael G. Morris
Thomas M. Hagan	Robert P. Powers
John B. Keane	Stephen P. Smith
Venita McCellon-Allen	Susan Tomasky

I&M

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 26, 2005, the following thirteen persons were elected directors to hold office for one year or until their successors are elected and qualify:

Karl G. Boyd	Venita McCellon-Allen
John E. Ehler	Susanne M. Moorman Rowe
Carl L. English	Michael G. Morris
Patrick C. Hale	Robert P. Powers
Holly K. Koeppel	John R. Sampson
David L. Lahrman	Susan Tomasky
Marc E. Lewis	

OPCo

The annual meeting of shareholders was held on May 3, 2005 at 1 Riverside Plaza, Columbus, Ohio. At the meeting there were 27,952,473 votes cast FOR each of the following eight persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

Carl L. English	Michael G. Morris
John B. Keane	Robert P. Powers
Holly K. Koeppel	Stephen P. Smith
Venita McCellon-Allen	Susan Tomasky

SWEPCo

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 13, 2005, the following eight persons were elected directors to hold office for one year or until their successors are elected and qualify:

Carl L. English	Michael G. Morris
Thomas M. Hagan	Robert P. Powers
John B. Keane	Stephen P. Smith
Venita McCellon-Allen	Susan Tomasky

Item 5. Other Information

NONE

Item 6. Exhibits

AEP

31(a) - Certification of AEP Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(c) - Certification of AEP Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, OPCo

10(a) - AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005.
10(b) - AEP System Incentive Compensation Deferral Plan, Amended and Restated as of January 1, 2005.

AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

12 - Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

31(b) - Certification of Registrant Subsidiaries' Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(d) - Certification of Registrant Subsidiaries' Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

32(a) - Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
32(b) - Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

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

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: August 4, 2005

EXHIBIT 12

KENTUCKY POWER COMPANY
Computation of Ratios of Earnings to Fixed Charges
(in thousands except ratio data)

	Year Ended December 31,					Twelve Months Ended
	2000	2001	2002	2003	2004	6/30/05
FIXED CHARGES						
Interest on First Mortgage Bonds	$ 9,503	$ 6,178	$ 2,206	$ -	$ -	$ -
Interest on Other Long-term Debt	16,367	18,300	23,429	26,467	27,051	26,747
Interest on Short-term Debt	3,295	2,329	1,751	1,104	697	349
Miscellaneous Interest Charges	2,523	1,059	1,084	1,772	1,956	2,025
Estimated Interest Element in Lease Rentals	1,700	1,200	1,000	600	700	700
Total Fixed Charges	$ 33,388	$ 29,066	$ 29,470	$ 29,943	$ 30,404	$ 29,821
EARNINGS						
Net Income Before Cumulative Effect of Accounting Change	$ 20,763	$ 21,565	$ 20,567	$ 33,464	$ 25,905	$ 22,556
Plus Federal Income Taxes	17,884	9,553	9,235	9,764	8,974	6,248
Plus State Income Taxes (Credits)	2,457	489	1,627	(89)	(303)	(540)
Plus Fixed Charges (as above)	33,388	29,066	29,470	29,943	30,404	29,821
Total Earnings	$ 74,492	$ 60,673	$ 60,899	$ 73,082	$ 64,980	$ 58,085
Ratio of Earnings to Fixed Charges	2.23	2.08	2.06	2.44	2.13	1.94

Exhibit 31(b)

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Michael G. Morris, certify that:

1. I have reviewed this report on Form 10-Q of:

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;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements

were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. Each registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. Each registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2005

By: /s/ Michael G. Morris
Michael G. Morris
Chief Executive Officer

Exhibit 31(d)

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Susan Tomasky, certify that:

1. I have reviewed this report on Form 10-Q of:

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;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. Each registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. Each registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2005 By: /s/ Susan Tomasky

Susan Tomasky
Chief Financial Officer

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of the Companies (as defined below) on Form 10-Q (the "Reports") for the quarterly period ended June 30, 2005 as filed with the Securities and Exchange Commission on the date hereof, I, Michael G. Morris, the chief executive officer of

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

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Michael G. Morris
Michael G. Morris
Chief Executive Officer

August 4, 2005

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of the Companies (as defined below) on Form 10-Q (the “Reports”) for the quarterly period ended June 30, 2005 as filed with the Securities and Exchange Commission on the date hereof, I, Susan Tomasky, the chief financial officer of

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

(the “Companies”), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Susan Tomasky
Susan Tomasky
Chief Financial Officer

August 4, 2005

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.