AMERICAN ELECTRIC POWER CO INC
Form 10-Q
August 03, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **June 30, 2007**
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

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

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

Large accelerated filer X Accelerated filer Non-accelerated filer

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

Large accelerated filer *Accelerated filer* *Non-accelerated filer X*

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

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

	Number of shares of common stock outstanding of the registrants at July 31, 2007
American Electric Power Company, Inc.	399,203,993
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Columbus Southern Power Company	16,410,426
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
June 30, 2007

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

GLOSSARY OF TERMS

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

Term	Meaning
ADITC	Accumulated Deferred Investment Tax Credits.
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income (Loss).
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CTC	Competition Transition Charge.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
E&R	Environmental compliance and transmission and distribution system reliability.
ECAR	East Central Area Reliability Council.
EDFIT	Excess Deferred Federal Income Taxes.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.

FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46	FIN 46, "Consolidation of Variable Interest Entities."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
GAAP	Accounting Principles Generally Accepted in the United States of America.
HPL	Houston Pipeline Company, a former AEP subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
IPP	Independent Power Producer.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
NYMEX	New York Mercantile Exchange.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO, SWEPCo.
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 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including the potential for new legislation in Ohio and membership in and integration into regional transmission organizations.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

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

EXECUTIVE OVERVIEW

Regulatory Activity

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

Operating Company	Jurisdiction	Revised Annual Rate Increase Request	Implemented Annual Rate Increase	Effective Date of Rate Increase
		(in millions)		
APCo	Virginia	$ 198(a)	$ 24(a)	October 2006
OPCo	Ohio	8	8(b)	May 2007
CSPCo	Ohio	24	24(b)	May 2007
TCC	Texas	81	70(b)	June 2007
TNC	Texas	25	14	June 2007
PSO	Oklahoma	50	9(b)	July 2007

(a) The difference between the requested and implemented amounts of annual rate increase is partially offset by approximately $35 million of incremental E&R costs which APCo anticipates to file for recovery through the E&R surcharge mechanism in 2008. APCo also requested a net $50 million reduction, beginning September 1, 2007, in credits to customers for off-system sales margins as part of its July 2007 fuel clause filing under the new re-regulation legislation.
(b) Rate increase is presently subject to refund. Proceeding is on-going.

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

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

West Virginia IGCC

In June 2007, APCo filed testimony with the WVPSC supporting construction of a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, WV. APCo requested pre-approval of a surcharge rate mechanism to provide for the timely recovery of both the ongoing finance costs of the project during the construction period as well as the capital and operating costs and a return on equity once the facility is placed into commercial operation. In July 2007, APCo filed a request with the Virginia SCC to recover an estimated $45 million in financing costs on projected IGCC construction work in progress including pre-construction development design and planning costs from July 1, 2007 through December 31, 2009. If APCo receives all necessary approvals, the plant could be completed as early as mid-2012 for an estimated cost of $2.2 billion.

Indiana Depreciation Study

In June 2007, the IURC approved a settlement agreement allowing I&M to implement reduced book depreciation rates upon the filing by I&M of a general rate petition. On June 19, 2007, I&M filed its rate petition to be effective on July 1, 2007. The settlement agreement will result in a reduction of book depreciation expense of $37 million primarily related to the Cook Plant license extension for the period from June 19, 2007 to December 31, 2007, which was offset by a $5 million regulatory liability, recorded in June 2007, to provide for an agreed-upon fuel credit. I&M expects new base rates including the reduced depreciation to become effective in late 2008 or early 2009.

Indiana Rate Cap

Effective July 1, 2007, I&M's rate cap ended for both base and fuel rates. I&M's fuel factor increased effective with July 2007 billings to recover the full projected cost of fuel. I&M will resume deferring through revenues any under/over-recovered fuel costs for future recovery/refund.

SWEPCo Fuel Reconciliation – Texas

In June 2007, an ALJ issued a Proposal for Decision recommending a $17 million disallowance in SWEPCo's Texas fuel reconciliation proceeding. Results of operations for the second quarter were adversely affected by $25 million as a result of reflecting the ALJ's decision. In July 2007, the PUCT orally affirmed the ALJ report. A final order is expected in the third quarter of 2007.

Virginia Restructuring

In April 2007, the Virginia legislature re-regulated electric utilities' generation/supply rates on a cost basis effective July 1, 2007. We recorded an extraordinary pretax reduction in APCo's earnings of $118 million ($79 million, net of tax) from reapplication of SFAS 71 regulatory accounting in the second quarter of 2007 as a result of the new re-regulation legislation.

Investment Activity

In the second quarter of 2007, we completed the purchase of the 480 MW Darby Electric Generation Station for $102 million and the purchase of the 1,096 MW Lawrenceburg Generating Station for $325 million.

RESULTS OF OPERATIONS

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

Utility Operations

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

MEMCO Operations

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

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities primarily in ERCOT.

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in millions)			
Utility Operations	$ 238	$ 159	$ 491	$ 524
MEMCO Operations	7	14	22	35
Generation and Marketing	15	2	14	6
All Other (a)	(3)	(3)	1	(15)
Income Before Discontinued Operations and Extraordinary Loss	$ 257	$ 172	$ 528	$ 550

(a) All Other includes:

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

Second Quarter of 2007 Compared to Second Quarter of 2006

Income Before Discontinued Operations and Extraordinary Loss in 2007 increased $85 million compared to 2006 primarily due to an increase in Utility Operations segment earnings of $79 million. The increase in Utility Operations segment earnings primarily relates to higher retail margins mostly due to rate increases and favorable weather and increased margins from off-system sales.

Average basic shares outstanding increased to 399 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation plans. Actual shares outstanding were 399 million as of June 30, 2007.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Income Before Discontinued Operations and Extraordinary Loss in 2007 decreased $22 million compared to 2006 primarily due to a decrease in Utility Operations segment earnings of $33 million. The decrease in Utility Operations segment earnings primarily relates to higher operation and maintenance expenses, higher regulatory amortization expense and lower earnings-sharing payments from Centrica received in March 2007 representing the last payment of the earnings-sharing agreement. These decreases in earnings were partially offset by rate increases and favorable weather.

Average basic shares outstanding increased to 398 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation plans. Actual shares outstanding were 399 million as of June 30, 2007.

Utility Operations

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

Utility Operations Income Summary
For the Three and Six Months Ended June 30, 2007 and 2006

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in millions)			
Revenues	$ 2,954	$ 2,796	$ 5,987	$ 5,762
Fuel and Purchased Power	1,109	1,123	2,228	2,249
Gross Margin	1,845	1,673	3,759	3,513
Depreciation and Amortization	365	346	748	686
Other Operating Expenses	957	983	1,948	1,819
Operating Income	523	344	1,063	1,008
Other Income, Net	27	44	45	85
Interest Charges and Preferred Stock Dividend Requirements	207	161	386	315
Income Tax Expense	105	68	231	254
Income Before Discontinued Operations and Extraordinary Loss	$ 238	$ 159	$ 491	$ 524

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

<u>**Energy/Delivery Summary**</u>	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in millions of KWH)			
Energy				
Retail:				
Residential	10,127	9,590	24,267	22,528
Commercial	10,227	9,440	19,586	18,349
Industrial	14,848	13,716	28,413	26,937
Miscellaneous	632	655	1,245	1,274
Total Retail	35,834	33,401	73,511	69,088
Wholesale	9,376	10,822	18,154	21,667
Delivery				
Texas Wires – Energy delivered to customers served by AEP’s Texas Wires Companies	6,746	6,915	12,577	12,461
Total KWHs	51,956	51,138	104,242	103,216

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on results of operations. In general, degree day changes in our eastern region have a larger effect on results of operations than changes in our western region due to the relative size of the two regions and the associated number of customers within each.

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in degree days)			
Weather Summary				
Eastern Region				
Actual – Heating (a)	222	107	2,039	1,563
Normal – Heating (b)	174	175	1,966	1,992
Actual – Cooling (c)	367	228	382	229
Normal – Cooling (b)	275	279	278	282
Western Region (d)				
Actual – Heating (a)	92	5	994	663
Normal – Heating (b)	33	33	991	1,005
Actual – Cooling (c)	622	815	678	858
Normal – Cooling (b)	656	652	674	669

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

<u>Second Quarter of 2007 Compared to Second Quarter of 2006</u>

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

Second Quarter of 2006		$ 159
Changes in Gross Margin:		
Retail Margins	72	
Off-system Sales	52	
Transmission Revenues	22	
Other Revenues	26	
Total Change in Gross Margin		172
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	26	
Depreciation and Amortization	(19)	
Carrying Costs Income	(17)	
Interest and Other Charges	(46)	
Total Change in Operating Expenses and Other		(56)
Income Tax Expense		(37)

Second Quarter of 2007	$	238

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $79 million to $238 million in 2007. The key drivers of the increase were a $172 million increase in Gross Margin partially offset by a $56 million increase in Operating Expenses and Other and a $37 million increase in Income Tax Expense.

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

- Retail Margins increased $72 million primarily due to the following:
  - A $36 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSP's.
  - A $36 million increase related to increased residential and commercial usage and customer growth.
  - A $24 million increase related to Ormet, a new industrial customer in Ohio. See "Ormet" section of Note 3.
  - A $19 million increase related to increased sales to municipal, cooperative and other customers primarily resulting from new power supply contracts.
  - A $26 million increase in usage related to weather. As compared to the prior year, our eastern region experienced a 61% increase in cooling degree days partially offset by a 24% decrease in cooling degree days in our western region.

  These increases were partially offset by:
  - A $38 million net decrease related to the APCo Virginia base rate case which includes a second quarter 2007 provision for revenue refund as a result of the final order offset by the new rates implemented. See "Virginia Base Rate Case" section of Note 3.
  - A $25 million decrease due to a second quarter 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding. See "SWEPCo Fuel Reconciliation – Texas" section of Note 3.
  - A $21 million decrease in financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market.
- Margins from Off-system Sales increased $52 million primarily due to higher power prices in the east and stronger trading margins offset by higher internal load and lower generation availability.
- Transmission Revenues increased $22 million primarily due to a provision recorded in the second quarter of 2006 related to potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.
- Other Revenues increased $26 million primarily due to higher securitization revenue at TCC resulting from the $1.7 billion securitization in October 2006. Securitization revenue represents amounts collected to recover securitization bond principal and interest payments related to TCC's securitized transition assets and are fully offset by amortization and interest expenses.

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

- Other Operation and Maintenance expenses decreased $26 million primarily due to reduced expenses for storm restoration and lower administrative and general expenses.
- Depreciation and Amortization expense increased $19 million primarily due to increased Ohio regulatory asset amortization related to recovery of IGCC pre-construction costs, increased Texas amortization of the securitized transition assets and higher depreciable property balances, offset by adjustments related to implementation of the final order in the APCo Virginia base rate case.
-

Carrying Costs Income decreased $17 million because TCC started recovering stranded costs in October 2006, thus eliminating future TCC carrying costs income.

- Interest and Other Charges increased $46 million primarily due to additional debt issued in the fourth quarter of 2006 including TCC securitization bonds.
- Income Tax Expense increased $37 million due to an increase in pretax income.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Reconciliation of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2007
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Six Months Ended June 30, 2006		$ 524
Changes in Gross Margin:		
Retail Margins	210	
Off-system Sales	11	
Transmission Revenues	(8)	
Other Revenues	33	
Total Change in Gross Margin		246
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(85)	
Gain on Dispositions of Assets, Net	(47)	
Depreciation and Amortization	(62)	
Taxes Other Than Income Taxes	3	
Carrying Costs Income	(39)	
Other Income, Net	(1)	
Interest and Other Charges	(71)	
Total Change in Operating Expenses and Other		(302)
Income Tax Expense		23
Six Months Ended June 30, 2007		$ 491

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss decreased $33 million to $491 million in 2007. The key driver of the decrease was a $302 million increase in Operating Expenses and Other, offset by a $246 million increase in Gross Margin and a $23 million decrease in Income Tax Expense.

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

- Retail Margins increased $210 million primarily due to the following:
  - A $71 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs and a $20 million increase related to new rates implemented in other east jurisdictions of Kentucky, West Virginia and Virginia.
  - A $70 million increase related to increased residential and commercial usage and customer growth.
  - A $66 million increase in usage related to weather. As compared to the prior year, our eastern region and western region experienced 30% and 50% increases, respectively, in heating degree days. Also, our eastern region experienced a 67% increase in cooling degree days which was offset by a

21% decrease in cooling degree days in our western region.
- A $37 million increase related to Ormet, a new industrial customer in Ohio. See “Ormet” section of Note 3.

These increases were partially offset by:
- A $48 million decrease in financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market.
- A $25 million decrease due to a second quarter 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding. See “SWEPCo Fuel Reconciliation – Texas” section of Note 3.

- Margins from Off-system Sales increased $11 million primarily due to higher power prices in the east and stronger trading margins offset by higher internal load and lower generation availability.
- Transmission Revenues decreased $8 million primarily due to the elimination of SECA revenues as of April 1, 2006 offset by a provision recorded in the second quarter of 2006 related to potential SECA refunds. See “Transmission Rate Proceedings at the FERC” section of Note 3.
- Other Revenues increased $33 million primarily due to higher securitization revenue at TCC resulting from the $1.7 billion securitization in October 2006. Securitization revenue represents amounts collected to recover securitization bond principal and interest payments related to TCC’s securitized transition assets and are fully offset by amortization and interest expenses.

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

- Other Operation and Maintenance expenses increased $85 million primarily due to increases in generation expenses related to plant outages, base operations and removal costs and distribution expenses associated with service reliability and storm restoration primarily in Oklahoma.
- Gain on Disposition of Assets, Net decreased $47 million primarily related to the earnings sharing agreement with Centrica from the sale of our REPs in 2002. In 2006, we received $70 million from Centrica for earnings sharing and in 2007 we received $20 million as the earnings sharing agreement ended.
- Depreciation and Amortization expense increased $62 million primarily due to increased Ohio regulatory asset amortization related to recovery of IGCC pre-construction costs, increased Texas amortization of the securitized transition assets and higher depreciable property balances.
- Carrying Costs Income decreased $39 million because TCC started recovering stranded costs in October 2006, thus eliminating future TCC carrying costs income.
- Interest and Other Charges increased $71 million primarily due to additional debt issued in the fourth quarter of 2006 including TCC securitization bonds.
- Income Tax Expense decreased $23 million due to a decrease in pretax income.

MEMCO Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

Income Before Discontinued Operations and Extraordinary Loss from our MEMCO Operations segment decreased from $14 million in 2006 to $7 million in 2007. While MEMCO operated 15% more barges in the second quarter of 2007 than the same period in 2006, freight revenues remained flat as spot market freight demand remained weaker than in 2006, primarily related to reduced steel and cement imports. Operating expenses were up 11% over the same period in 2006 mainly due to the increased fleet size, increased fuel costs and wage increases for towboat crews.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Income Before Discontinued Operations and Extraordinary Loss from our MEMCO Operations segment decreased from $35 million in 2006 to $22 million in 2007. MEMCO operated approximately 16% more barges in the first six months of 2007 than 2006, however, revenue remained flat as reduced imports, primarily steel and cement continued to depress freight rates and reduce northbound loadings. Operating expenses were up for the first six months of 2007 compared to 2006 primarily due to the cost of the increased fleet size, fuel and wage increases.

Generation and Marketing

Second Quarter of 2007 Compared to Second Quarter of 2006

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased from $2 million in 2006 to $15 million in 2007. The increase primarily relates to favorable marketing contracts with municipalities and cooperatives in ERCOT. Net revenues for our Generation and Marketing segment increased primarily due to certain existing ERCOT energy contracts which were transferred from our Utility Operations segment on January 1, 2007.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased from $6 million in 2006 to $14 million in 2007. The increase primarily relates to favorable marketing contracts with municipalities and cooperatives in ERCOT. Net revenues for our Generation and Marketing segment increased primarily due to certain existing ERCOT energy contracts which were transferred from our Utility Operations segment on January 1, 2007.

All Other

Second Quarter of 2007 Compared to Second Quarter of 2006

Loss Before Discontinued Operations and Extraordinary Loss from All Other was essentially flat at $3 million.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Income Before Discontinued Operations and Extraordinary Loss from All Other increased from a $15 million loss in 2006 to income of $1 million in 2007. In 2006, we had after-tax losses of $8 million from operation of the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. In 2007, we had an after-tax gain of $10 million on the sale of investment securities.

AEP System Income Taxes

Income Tax Expense increased $36 million in the second quarter of 2007 compared to the second quarter of 2006 primarily due to an increase in pretax book income.

Income Tax Expense decreased $23 million for the six-month period ended June 30, 2007 compared to the six-month period ended June 30, 2006 primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	June 30, 2007		December 31, 2006	
		($ in millions)		
Long-term Debt, Including Amounts Due Within One Year	$ 14,588	59.0%	$ 13,698	59.1%
Short-term Debt	438	1.8	18	0.0
Total Debt	15,026	60.8	13,716	59.1
Common Equity	9,656	39.0	9,412	40.6
Preferred Stock	61	0.2	61	0.3
Total Debt and Equity Capitalization	$ 24,743	100.0%	$ 23,189	100.0%

Our ratio of debt to total capital increased, as planned, from 59.1% to 60.8% in 2007 due to our increased borrowings.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At June 30, 2007, our available liquidity was approximately $2.7 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,500	April 2012
Total	3,000	
Cash and Cash Equivalents	172	
Total Liquidity Sources	3,172	
Less: AEP Commercial Paper Outstanding	416	
Letters of Credit Drawn	27	
Net Available Liquidity	$ 2,729	

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

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined in our revolving credit agreements. At June 30, 2007, this contractually-defined percentage was 56.1%. Nonperformance of these covenants could result in an event of default under these credit agreements. At June 30, 2007, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

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

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

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

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2007 and AEP is currently on a stable outlook by the rating agencies. Our current credit ratings are as follows:

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

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

<u>Cash Flow</u>

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

	Six Months Ended June 30,			
	2007		**2006**	
	(in millions)			
Cash and Cash Equivalents at Beginning of Period	$	301	$	401
Net Cash Flows From Operating Activities		969		1,123
Net Cash Flows Used For Investing Activities		(2,127)		(1,572)
Net Cash Flows From Financing Activities		1,029		297
Net Decrease in Cash and Cash Equivalents		(129)		(152)
Cash and Cash Equivalents at End of Period	$	172	$	249

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of June 30, 2007, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2007 was $833 million. The weighted-average interest rate of our commercial paper for the six months ended June 30, 2007 was 5.40%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

	Six Months Ended June 30,			
	2007		2006	
	(in millions)			
Net Income	$	451	$	556
Less: Discontinued Operations, Net of Tax		(2)		(6)
Income Before Discontinued Operations		449		550
Noncash Items Included in Earnings		938		617
Changes in Assets and Liabilities		(418)		(44)
Net Cash Flows From Operating Activities	$	969	$	1,123

Net Cash Flows From Operating Activities decreased in 2007 primarily due to lower fuel costs recovery.

Net Cash Flows From Operating Activities were $1 billion in 2007. We produced Income Before Discontinued Operations of $449 million adjusted for noncash expense items, primarily depreciation and amortization. Other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items, the most significant of which relates primarily to the Texas CTC refund of fuel over-recovery.

Net Cash Flows From Operating Activities were $1.1 billion in 2006. We produced Income Before Discontinued Operations of $550 million adjusted for noncash expense items, primarily depreciation and amortization. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. Under-recovered fuel costs decreased due to recovery of higher cost of fuel, especially natural gas. Other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are a $185 million cash increase from net Accounts Receivable/Accounts Payable due to a lower balance of Customer Accounts Receivable at June 30, 2006 and a $189 million decrease in cash related to customer deposits held for trading activities.

Investing Activities

	Six Months Ended June 30,			
	2007		2006	
	(in millions)			
Construction Expenditures	$	(1,823)	$	(1,611)
Change in Other Temporary Investments, Net		(129)		3
(Purchases)/Sales of Investment Securities, Net		208		(51)
Acquisition of Darby and Lawrenceburg Plants		(427)		-

Proceeds from Sales of Assets		74		118
Other		(30)		(31)
Net Cash Flows Used For Investing Activities	$	(2,127)	$	(1,572)

Net Cash Flows Used For Investing Activities were $2.1 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan. We paid $427 million to purchase gas-fired generating units. In our normal course of business, we purchase investment securities including auction rate securities and variable rate demand notes with cash available for short-term investments. Also included in Purchases/Sales of Investment Securities, Net are purchases and sales of securities within our nuclear trusts.

Net Cash Flows Used For Investing Activities were $1.6 billion in 2006 primarily due to Construction Expenditures. Construction Expenditures increased due to our environmental investment plan.

We forecast approximately $1.7 billion of construction expenditures for the remainder of 2007. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	Six Months Ended June 30,			
		2007		**2006**
	(in millions)			
Issuance of Common Stock	$	90	$	6
Issuance/Retirement of Debt, Net		1,294		552
Dividends Paid on Common Stock		(311)		(291)
Other		(44)		30
Net Cash Flows From Financing Activities	$	1,029	$	297

Net Cash Flows From Financing Activities in 2007 were $1 billion primarily due to issuing $1.1 billion of debt securities including $1 billion of new debt for plant acquisitions and construction and increasing short-term commercial paper borrowings. We paid common stock dividends of $311 million. See Note 9 for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows From Financing Activities in 2006 were $297 million. During 2006, we issued $115 million of obligations relating to pollution control bonds, issued $850 million of notes and retired $396 million of notes for a net increase in notes outstanding of $454 million and increased our short-term commercial paper outstanding by $144 million. The Other amount of $30 million in the above table includes $68 million received from a coal supplier, net of an $8 million repayment, related to a long-term coal purchase contract amended in March 2006.

Our capital investment plans for the remainder of 2007 will require additional funding of approximately $1.5 billion from the capital markets.

Off-balance Sheet Arrangements

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

	June 30, 2007	December 31, 2006
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 549	$ 536
Rockport Plant Unit 2 Future Minimum Lease Payments	2,290	2,364
Railcars Maximum Potential Loss From Lease Agreement	30	31

For complete information on each of these off-balance sheet arrangements see the "Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2006 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2006 Annual Report and has not changed significantly from year-end other than the debt issuances discussed in "Cash Flow" and "Financing Activities" above.

Other

Texas REPs

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

SIGNIFICANT FACTORS

We continue to be involved in various matters described in the "Significant Factors" section of Management's Financial Discussion and Analysis of Results of Operations in our 2006 Annual Report. The 2006 Annual Report should be read in conjunction with this report in order to understand significant factors without material changes in status since the issuance of our 2006 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition.

Ohio Restructuring

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Texas Restructuring

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

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

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

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

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

SECA Revenue Subject to Refund

The AEP East companies ceased collecting T&O revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. Approximately $19 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of AEP's SECA customers. The AEP East companies reached settlements with certain SECA customers related to approximately $69 million of such revenues for a net refund of $3 million. The AEP East companies are in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and will consume about $7 million of the reserves for refunds, leaving approximately $115 million of contested SECA revenues and $30 million of refund reserves. If the ALJ's initial decision were upheld in its entirety, it would disallow approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on recent settlement experience and the expectation that most of the $115 million of unsettled SECA revenues will be settled, management believes that the remaining reserve will be adequate.

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

Virginia Restructuring

In April 2004, Virginia enacted legislation that amended the Virginia Electric Utility Restructuring Act extending the transition period to market rates for the generation and supply of electricity, including the extension of capped rates, through December 31, 2010. The legislation provided APCo with specified cost recovery opportunities during the extended capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain unrecovered incremental environmental and reliability costs incurred on and after July 1, 2004. Under the amended restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the amended restructuring law, APCo has the right to defer incremental environmental compliance costs and incremental E&R costs for future recovery, to the extent such costs are not being recovered, and amortizes a portion of such deferrals commensurate with their recovery.

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

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

New Generation

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

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. Through June 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered. As of June 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all amounts collected for pre-construction costs, associated with items that may be utilized in IGCC projects to be built by AEP at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

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

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant are $2.2 billion. CSPCo and OPCo may need to request an extension to the 5 year start of construction requirement if the commencement of construction is delayed beyond 2011. In July 2007, CSPCo and OPCo filed a status report with the PUCO referencing APCo's IGCC West Virginia filing.

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

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

In July 2007, APCo filed a request with the Virginia SCC to recover, over the twelve months beginning January 1, 2009, a return on projected construction work in progress including development, design and planning costs from July 1, 2007 through December 31, 2009 estimated to be $45 million associated with the IGCC plant to be constructed in West Virginia. APCo is requesting authorization to defer a return on actual pre-construction costs incurred beginning July 1, 2007 until such costs are recovered, starting January 1, 2009 as required by the new re-regulation legislation.

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct new generation to satisfy the demands of its customers. Plans include the construction of up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and a 480 MW combined-cycle natural gas fired intermediate plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build the Turk plant, a new 600 MW base load coal plant, with a 73% ownership share, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of its customers. Preliminary cost estimates for SWEPCo’s share of these new facilities are approximately $1.4 billion (this total includes all three plants, but excludes the related transmission investment and AFUDC). Expenditures related to construction of all of these facilities are expected to total $349 million in 2007. These new facilities are subject to regulatory approvals from SWEPCo’s three state commissions. Mattison plant, the peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions. Mattison plant Units 3 and 4 began commercial operation in July 2007, with the remaining two units scheduled for completion in December 2007. All four units of the Mattison plant are expected to be completed in advance of the originally planned 2008 commercial operation date. Construction is expected to begin in the second half of 2007 on the base load facility and in 2008 on the intermediate facility, both upon approval from SWEPCo’s three state commissions.

In September 2005, PSO sought proposals for new peaking generation to be online in 2008, and in December 2005 PSO sought proposals for base load generation to be online in 2011. PSO received proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In March 2006, PSO announced plans to add 170 MW of peaking generation to its Riverside Station plant in Jenks, Oklahoma where PSO will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Also in March 2006, PSO announced plans to add 170 MW of peaking generation to its Southwestern Station plant in Anadarko, Oklahoma where they will construct and operate two 85 MW simple-cycle natural gas combustion turbines. Construction of all four peaking units began in the second quarter of 2007. Combined preliminary cost estimates for these additions are approximately $120 million. In April 2007, the OCC approved a settlement agreement in a matter involving a proposed cogeneration facility, which included a provision regarding these new peaking units. The settlement agreement provides for recovery of a purchase fee of $35 million, which PSO paid to Lawton Cogeneration, LLC (Lawton) in the second quarter of 2007 to settle the proceeding and for all rights to Lawton’s permits, options and engineering studies for the cogeneration facility. In April 2007, PSO recorded with OCC approval, the purchase fee as a regulatory asset and will recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover the traditional costs associated with plant in service of these new peaking units. Such costs will be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units.

In July 2006, PSO announced plans to enter a joint ownership agreement with Oklahoma Gas and Electric Company (OG&E) and Oklahoma Municipal Power Authority (OMPA) where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. PSO will own 50% of the new unit. PSO, OG&E and OMPA signed an agreement in February 2007 with Red Rock Power Partners to begin the first phase of the project. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion, and the unit is expected to be online no later than the first half of 2012. This new facility is subject to regulatory approval from the OCC, which is expected later in 2007. Construction is expected to begin in the second half of 2007. The Oklahoma Supreme Court is addressing whether the upfront approval process is constitutional. PSO estimates construction expenditures for all of the new generation projects to be $167 million in 2007.

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for $102 million and the assumption of liabilities of $2 million. CSPCo completed the purchase in April 2007. The Darby plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW. The purchase of Darby is an economically efficient way to provide peaking generation to our customers at a cost below that of building a new, comparable plant.

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

Electric Transmission Texas LLC Joint Venture

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

TCC also made a regulatory filing at the FERC in February 2007 regarding the transfer of certain transmission assets from TCC to ETT. In April 2007, the FERC authorized the transfer.

Upon receipt of all required regulatory approvals, AEP Utilities, Inc., a subsidiary of AEP, and MEHC Texas Transco LLC, a subsidiary of MidAmerican, each will acquire a 50 percent equity ownership in ETT. AEP and MidAmerican plan for ETT to invest in additional transmission projects in ERCOT. The joint venture partners anticipate investments in excess of $1 billion of joint investment in Texas ERCOT Transmission projects that could be constructed by ETT during the next several years. The joint venture is anticipated to be formed and begin operations in the fourth quarter of 2007, subject to certain closing conditions such as necessary regulatory approvals.

In February 2007, ETT filed a proposal with the PUCT that addresses the Competitive Renewable Energy Zone (CREZ) initiative of the Texas Legislature, which outlines opportunities for additional significant investment in transmission assets in Texas. A CREZ hearing was held in June 2007. We expect an order in August 2007 on the designation of zones and amount of wind generation for each zone, subsequent studies by ERCOT on specific transmission recommendations in late 2007 or early 2008 and selection of transmission construction designees by the

PUCT in early 2008.

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

AEP Interstate Project

In January 2006, we filed a proposal with the FERC and PJM to build a new 765 kV 550-mile transmission line from West Virginia to New Jersey. The 765 kV line is designed to reduce PJM congestion costs by substantially improving west-east transfer capability by approximately 5,000 MW during peak loading conditions and reducing transmission line losses by up to 280 MW. The project would also enhance reliability of the Eastern transmission grid. The projected cost for the project, as originally proposed to PJM, is approximately $3 billion. The project is subject to PJM and state approvals, and FERC approvals of incentive cost recovery mechanisms.

We were the first entity to file with the Department of Energy (DOE) seeking to have the route of a proposed transmission project designated as a National Interest Electric Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. In August 2006, the DOE issued the "National Interest Electric Transmission Congestion Study." In this study, DOE indicated that the mid-Atlantic Coastal area, which the AEP Interstate Project is designed to reinforce, is one of the two most critical congestion areas in the nation. In April 2007, the DOE included in its draft report the mid-Atlantic Coastal area NIETC which contains the entire proposed 765 kV transmission line. The DOE expects to issue its final report by the end of 2007.

In July 2006, pursuant to our request, the FERC clarified that the project qualifies for incentive rate treatment, provided that the new line is included in PJM's 2007 Regional Transmission Expansion Plan. The conditionally-approved incentives include (a) a return on equity set at the high end of the "zone of reasonableness"; (b) the timely recovery of the cost of capital during the construction period; and (c) the ability to defer and recover costs incurred during the pre-construction and pre-operating period. Since the FERC has clarified that the project qualifies for these rate incentives, we expect to propose rates that will capture the incentives in a future FERC rate filing.

In April 2007, we signed a memorandum of understanding (MOU) with Allegheny Energy Inc. (AYE) to form a joint venture company to build and own certain electric transmission assets within PJM including the first half of the West Virginia – New Jersey line proposed by AEP in January 2006. Under the terms of the MOU, the joint venture company will build and own approximately 300 miles of transmission lines from AEP's Amos station to the Maryland border. The MOU does not include any provisions for the remainder of the AEP Interstate Project proposal from AYE's Kemptown station to New Jersey.

On June 22, 2007, PJM's Board authorized the construction of such a major new transmission line to address the reliability and efficiency needs of the PJM system. PJM has identified a need for a new line as early as 2012. The line would be 765kV for most of its length and would run approximately 250 miles from AEP's Amos substation in West Virginia to AYE's Kemptown station in north central Maryland. AEP and AYE continue to work on finalizing the definitive agreements necessary to construct the line through a joint venture. The new line has been named the "Potomac-Appalachian Transmission Highline" (PATH) by AEP and AYE and represents the "first leg" of the AEP Interstate Project. The "second leg", which would extend the line to New Jersey, is currently under evaluation by PJM. We expect to execute definitive agreements for the joint venture with AYE in the third quarter of 2007 and anticipate the joint venture will begin activities in the second half of 2007. The total PATH project is estimated to cost approximately $1.8 billion and AEP's estimated share will be approximately $600 million.

Litigation

In the ordinary course of business, we and our subsidiaries are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and the loss amount can be estimated. For details on regulatory proceedings and our pending litigation see Note 4 – Rate Matters, Note 6 – Commitments, Guarantees and Contingencies and the “Litigation” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2006 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to materially affect the results of operations, cash flows and financial condition of AEP and its subsidiaries.

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

Environmental Matters

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

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

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

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. Several similar complaints were filed in 1999 and thereafter against nonaffiliated utilities including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during 2005. In 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

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

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case.

In April 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on the merits of arguments in our NSR proceedings, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of our NSR proceedings. The court indicated an intent to issue a decision on liability issues in the third quarter of 2007. A bench trial on remedy issues, if necessary, is likely to begin in the second half of 2007.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, we might have for civil penalties under the 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 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.

Clean Water Act Regulations

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

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. We adopted FIN 48 effective January 1, 2007. The effect of this interpretation on our financial statements was an unfavorable adjustment to retained earnings of $17 million. See “FIN 48 “Accounting for Uncertainty in Income Taxes” and FASB Staff Position FIN 48-1 “Definition of *Settlement* in FASB Interpretation No. 48”” section of Note 2 and Note 8 – Income Taxes.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

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

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

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

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. We support the work of the CCRO and embrace the disclosure standards applicable to our business activities. The following tables provide information on our risk management activities.

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

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

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

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

					Value Hedges	
Current Assets	$ 305	$ 40	$ 83	$ 428	$ 39	$ 467
Noncurrent Assets	197	46	98	341	15	356
Total Assets	502	86	181	769	54	823
Current Liabilities	(215)	(50)	(83)	(348)	(3)	(351)
Noncurrent Liabilities	(91)	(11)	(105)	(207)	(1)	(208)
Total Liabilities	(306)	(61)	(188)	(555)	(4)	(559)
Total MTMDerivative Contract Net Assets (Liabilities)	$ 196	$ 25	$ (7)	$ 214	$ 50	$ 264

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

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	$ 236	$ 2	$ (5)	$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(37)	(1)	(1)	(39)
Fair Value of New Contracts at Inception When Entered During the Period (a)	1	31	-	32
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	1	-	-	1
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	8	(7)	(1)	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(13)	-	-	(13)
Total MTM Risk Management Contract Net Assets (Liabilities) at June 30, 2007	$ 196	$ 25	$ (7)	214
Net Cash Flow and Fair Value Hedge Contracts				50
Total MTM Risk Management Contract Net Assets at June 30, 2007				$ 264

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

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

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

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

The following table presents:

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

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

	Remainder 2007	2008	2009	2010	2011	After 2011 (c)	Total
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (6)	$ (8)	$ -	$ -	$ -	$ -	$ (14)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	73	56	37	17	-	-	183
Prices Based on Models and Other Valuation Methods (b)	(4)	(3)	8	17	4	5	27
Total	63	45	45	34	4	5	196
Generation and Marketing:							
Prices Actively Quoted – Exchange Traded Contracts	(8)	(2)	2	-	-	-	(8)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(5)	8	3	-	-	-	6
Prices Based on Models and Other Valuation Methods (b)	1	2	(3)	6	5	16	27
Total	(12)	8	2	6	5	16	25
All Other:							
Prices Actively Quoted – Exchange Traded Contracts	2	-	-	-	-	-	2
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(1)	-	-	-	-	-	(1)
Prices Based on Models and Other Valuation Methods (b)	(1)	(1)	(4)	(4)	2	-	(8)
Total	-	(1)	(4)	(4)	2	-	(7)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	(12)	(10)	2	-	-	-	(20)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	67	64	40	17	-	-	188
Prices Based on Models and Other Valuation Methods (b)	(4)	(2)	1	19	11	21	46
Total	$ 51	$ 52	$ 43	$ 36	$ 11	$ 21	$ 214

(a) Prices Provided by Other External Sources – OTC Broker Quotes reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party online platforms.
(b) Prices Based on Models and Other Valuation Methods is used in the absence of independent information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled. Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available including values determinable by other third party transactions.
(c) There is mark-to-market value of $21 million in individual periods beyond 2011. $10 million of this mark-to-market value is in 2012, $5 million is in 2013, and $5 million is in 2014, and $1 million for years 2015 through 2017.

The determination of the point at which a market is no longer supported by independent quotes and therefore considered in the modeled category in the preceding table varies by market. The following table generally reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of June 30, 2007

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	16
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	16
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	30
	Physical Forwards	AEP East	42
	Physical Forwards	AEP West	18
	Physical Forwards	West Coast	30
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	30
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 operations. We monitor these risks on our future operations and may use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

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

We use forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2006 to June 30, 2007. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

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

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2006	$ 17	$ (23)	$ (6)
Changes in Fair Value	22	5	27
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(13)	1	(12)
Ending Balance in AOCI, June 30, 2007	$ 26	$ (17)	$ 9
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 20	$ -	$ 20

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of June 30, 2007, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 4.9%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of June 30, 2007, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties>10% of Net Exposure	Net Exposure of Counterparties>10%
Investment Grade	$ 723	$ 81	$ 642	1	$ 67
Split Rating	20	2	18	3	17
Noninvestment Grade	30	7	23	1	19
No External Ratings:					
Internal Investment Grade	71	-	71	1	30
Internal Noninvestment Grade	17	2	15	1	11
Total as of June 30, 2007	$ 861	$ 92	$ 769	7	$ 144
Total as of December 31, 2006	$ 998	$ 161	$ 837	9	$ 169

<u>Generation Plant Hedging Information</u>

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

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

	Remainder 2007	2008	2009
Estimated Plant Output Hedged	94%	90%	91%

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

Commodity Price Risk

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2007, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

Six Months Ended June 30, 2007 (in millions)				Twelve Months Ended December 31, 2006 (in millions)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$1	$6	$2	$1	$3	$10	$3	$1

The High VaR for 2006 occurred in mid-August during a period of high gas and power volatility. The following day, positions were flattened and the VaR was significantly reduced.

Interest Rate Risk

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $912 million at June 30, 2007 and $870 million at December 31, 2006. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2007 and 2006
(in millions, except per-share amounts and shares outstanding)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Utility Operations	$ 2,818	$ 2,799	$ 5,704	$ 5,781
Other	328	137	611	263
TOTAL	3,146	2,936	6,315	6,044
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	868	888	1,754	1,849
Purchased Energy for Resale	291	237	537	403
Other Operation and Maintenance	881	896	1,819	1,717
Gain on Disposition of Assets, Net	(3)	-	(26)	(68)
Depreciation and Amortization	372	354	763	702
Taxes Other Than Income Taxes	188	190	374	381
TOTAL	2,597	2,565	5,221	4,984
OPERATING INCOME	549	371	1,094	1,060
Interest and Investment Income	8	11	31	19
Carrying Costs Income	16	33	24	63
Allowance For Equity Funds Used During Construction	6	7	14	13
Gain on Disposition of Equity Investments, Net	-	-	-	3
INTEREST AND OTHER CHARGES				
Interest Expense	213	176	399	344
Preferred Stock Dividend Requirements of Subsidiaries	-	-	1	1
TOTAL	213	176	400	345
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS (LOSS)	366	246	763	813
Income Tax Expense	108	72	238	261
Minority Interest Expense	1	1	2	1
Equity Earnings (Loss) of Unconsolidated Subsidiaries	-	(1)	5	(1)
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	257	172	528	550

DISCONTINUED OPERATIONS, NET OF TAX		2		3		2		6
INCOME BEFORE EXTRAORDINARY LOSS		259		175		530		556
EXTRAORDINARY LOSS, NET OF TAX		(79)		-		(79)		-
NET INCOME	$	180	$	175	$	451	$	556
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		398,679,242		393,722,353		398,000,712		393,687,949
BASIC EARNINGS PER SHARE								
Income Before Discontinued Operations and Extraordinary Loss	$	0.64	$	0.44	$	1.33	$	1.40
Discontinued Operations, Net of Tax		0.01		-		-		0.01
Income Before Extraordinary Loss		0.65		0.44		1.33		1.41
Extraordinary Loss, Net of Tax		(0.20)		-		(0.20)		-
TOTAL BASIC EARNINGS PER SHARE	$	0.45	$	0.44	$	1.13	$	1.41
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		399,868,900		395,500,506		399,214,277		395,540,498
DILUTED EARNINGS PER SHARE								
Income Before Discontinued Operations and Extraordinary Loss	$	0.64	$	0.43	$	1.32	$	1.39
Discontinued Operations, Net of Tax		0.01		0.01		0.01		0.02
Income Before Extraordinary Loss		0.65		0.44		1.33		1.41
Extraordinary Loss, Net of Tax		(0.20)		-		(0.20)		-
TOTAL DILUTED EARNINGS PER SHARE	$	0.45	$	0.44	$	1.13	$	1.41
CASH DIVIDENDS PAID PER SHARE	$	0.39	$	0.37	$	0.78	$	0.74

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 172	$ 301
Other Temporary Investments	337	425
Accounts Receivable:		
Customers	676	676
Accrued Unbilled Revenues	378	350
Miscellaneous	58	44
Allowance for Uncollectible Accounts	(40)	(30)
Total Accounts Receivable	1,072	1,040
Fuel, Materials and Supplies	1,038	913
Risk Management Assets	467	680
Regulatory Asset for Under-Recovered Fuel Costs	28	38
Margin Deposits	75	120
Prepayments and Other	74	71
TOTAL	3,263	3,588
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	19,618	16,787
Transmission	7,275	7,018
Distribution	11,718	11,338
Other (including coal mining and nuclear fuel)	3,320	3,405
Construction Work in Progress	2,469	3,473
Total	44,400	42,021
Accumulated Depreciation and Amortization	(15,933)	(15,240)
TOTAL - NET	28,467	26,781
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,405	2,477
Securitized Transition Assets	2,116	2,158
Spent Nuclear Fuel and Decommissioning Trusts	1,311	1,248
Goodwill	76	76
Long-term Risk Management Assets	356	378
Employee Benefits and Pension Assets	303	327
Deferred Charges and Other	896	910
TOTAL	7,463	7,574
Assets Held for Sale	-	44
TOTAL ASSETS	$ 39,193	$ 37,987

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2007 and December 31, 2006
(Unaudited)

	2007	2006
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,189	$ 1,360
Short-term Debt	438	18
Long-term Debt Due Within One Year	1,521	1,269
Risk Management Liabilities	351	541
Customer Deposits	353	339
Accrued Taxes	783	781
Accrued Interest	291	186
Other	878	962
TOTAL	5,804	5,456
NONCURRENT LIABILITIES		
Long-term Debt	13,067	12,429
Long-term Risk Management Liabilities	208	260
Deferred Income Taxes	4,536	4,690
Regulatory Liabilities and Deferred Investment Tax Credits	2,936	2,910
Asset Retirement Obligations	1,047	1,023
Employee Benefits and Pension Obligations	838	823
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	143	148
Deferred Credits and Other	897	775
TOTAL	23,672	23,058
TOTAL LIABILITIES	29,476	28,514
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		
2007 / 2006		
Shares Authorized 600,000,000 / 600,000,000		
Shares Issued 420,689,766 / 418,174,728		
(21,499,992 shares were held in treasury at June 30, 2007 and December 31, 2006)	2,734	2,718
Paid-in Capital	4,305	4,221
Retained Earnings	2,819	2,696
Accumulated Other Comprehensive Income (Loss)	(202)	(223)
TOTAL	9,656	9,412
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 39,193	$ 37,987

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2007 and 2006
(in millions)
(Unaudited)

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 451	$ 556
Less: Discontinued Operations, Net of Tax	(2)	(6)
Income Before Discontinued Operations	449	550
Adjustments for Noncash Items:		
Depreciation and Amortization	763	702
Deferred Income Taxes	(24)	10
Deferred Investment Tax Credits	(13)	(14)
Extraordinary Loss	79	-
Regulatory Provision	105	-
Carrying Costs Income	(24)	(63)
Mark-to-Market of Risk Management Contracts	19	(43)
Amortization of Nuclear Fuel	33	25
Deferred Property Taxes	24	12
Fuel Over/Under-Recovery, Net	(101)	128
Gain on Sales of Assets and Equity Investments, Net	(26)	(71)
Change in Other Noncurrent Assets	(53)	82
Change in Other Noncurrent Liabilities	23	(12)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(81)	202
Fuel, Materials and Supplies	(90)	(140)
Margin Deposits	45	67
Accounts Payable	(58)	(17)
Customer Deposits	14	(189)
Accrued Taxes, Net	49	90
Accrued Interest	67	1
Other Current Assets	(21)	19
Other Current Liabilities	(210)	(216)
Net Cash Flows From Operating Activities	969	1,123
INVESTING ACTIVITIES		
Construction Expenditures	(1,823)	(1,611)
Change in Other Temporary Investments, Net	(129)	3
Purchases of Investment Securities	(6,827)	(5,647)
Sales of Investment Securities	7,035	5,596
Acquisition of Darby and Lawrenceburg Plants	(427)	-
Proceeds from Sales of Assets	74	118
Other	(30)	(31)
Net Cash Flows Used For Investing Activities	(2,127)	(1,572)
FINANCING ACTIVITIES		
Issuance of Common Stock	90	6
Change in Short-term Debt, Net	420	147
Issuance of Long-term Debt	1,064	1,081

Retirement of Long-term Debt		(190)		(676)
Dividends Paid on Common Stock		(311)		(291)
Other		(44)		30
Net Cash Flows From Financing Activities		1,029		297
Net Decrease in Cash and Cash Equivalents		(129)		(152)
Cash and Cash Equivalents at Beginning of Period		301		401
Cash and Cash Equivalents at End of Period	$	172	$	249
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	304	$	316
Net Cash Paid for Income Taxes		128		123
Noncash Acquisitions Under Capital Leases		23		37
Construction Expenditures Included in Accounts Payable at June 30,		295		273
Acquisition of Nuclear Fuel in Accounts Payable at June 30,		31		26
Noncash Assumption of Liabilities Related to Acquisitions		5		-

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2007 and 2006
(in millions)
(Unaudited)

	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	415	$ 2,699	$ 4,131	$ 2,285	$ (27)	$ 9,088
Issuance of Common Stock		1	5			6
Common Stock Dividends				(291)		(291)
Other			2			2
TOTAL						8,805
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Cash Flow Hedges, Net of Tax of $29					54	54
Securities Available for Sale, Net of Tax of $6					11	11
NET INCOME				556		556
TOTAL COMPREHENSIVE INCOME						621
JUNE 30, 2006	415	$ 2,700	$ 4,138	$ 2,550	$ 38	$ 9,426
DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 9,412
FIN 48 Adoption, Net of Tax				(17)		(17)
Issuance of Common Stock	3	16	74			90
Common Stock Dividends				(311)		(311)
Other			10			10
TOTAL						9,184
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Cash Flow Hedges, Net of Tax of $8					15	15
Securities Available for Sale, Net of Tax of $3					(5)	(5)
SFAS 158 Costs Established as a Regulatory Asset for the Reapplication of SFAS 71, Net					11	11

of Tax of $6						
NET INCOME				451		451
TOTAL COMPREHENSIVE INCOME						472
JUNE 30, 2007	421	$ 2,734	$ 4,305	$ 2,819	$ (202)	$ 9,656

See Condensed Notes to Condensed Consolidated Financial Statements.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods. The results of operations for the three or six months ended June 30, 2007 are not necessarily indicative of results that may be expected for the year ending December 31, 2007. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2006 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2006 as filed with the SEC on February 28, 2007.

Property, Plant and Equipment and Equity Investments

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

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

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

Revenue Recognition

Traditional Electricity Supply and Delivery Activities

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

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

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

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

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

Energy Marketing and Risk Management Activities

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

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

Management Assets or Liabilities as appropriate.

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

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

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

Components		June 30, 2007		December 31, 2006
		(in millions)		
Securities Available for Sale, Net of Tax	$	13	$	18
Cash Flow Hedges, Net of Tax		9		(6)
SFAS 158 Costs, Net of Tax		(224)		(235)
Total	$	(202)	$	(223)

At June 30, 2007, during the next twelve months, we expect to reclassify approximately $20 million of net gains from cash flow hedges in AOCI to Net Income during the next twelve months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from AOCI to Net Income can differ as a result of market fluctuations.

At June 30, 2007, thirty-six months is the maximum length of time that our exposure to variability in future cash flows is hedged with contracts designated as cash flow hedges.

Earnings Per Share (EPS)

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

	Three Months Ended June 30,					
	2007			2006		
	(in millions, except per share data)					
			$/share			$/share
Earnings Applicable to Common Stock	$	180		$	175	
Average Number of Basic Shares Outstanding		398.7	$ 0.45		393.7	$ 0.44
Average Dilutive Effect of:						

Performance Share Units	0.6		-	1.4		-
Stock Options	0.4		-	0.2		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	0.1		-
Average Number of Diluted Shares Outstanding	399.9	$	0.45	395.5	$	0.44

	Six Months Ended June 30,					
	2007			2006		
	(in millions, except per share data)					
		$/share			$/share	
Earnings Applicable to Common Stock	$	451		$	556	
Average Number of Basic Shares Outstanding	398.0	$	1.13	393.7	$	1.41
Average Dilutive Effect of:						
Performance Share Units	0.6		-	1.4		-
Stock Options	0.4		-	0.2		-
Restricted Stock Units	0.1		-	0.1		-
Restricted Shares	0.1		-	0.1		-
Average Number of Diluted Shares Outstanding	399.2	$	1.13	395.5	$	1.41

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

Options to purchase 0.1 million and 4.3 million shares of common stock were outstanding at June 30, 2007 and 2006, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares for the period and, therefore, the effect would not be dilutive.

Supplementary Information

	Three Months Ended June 30,				Six Months Ended June 30,			
	2007		2006		2007		2006	
Related Party Transactions	(in millions)				(in millions)			
AEP Consolidated Purchased Energy:								
Ohio Valley Electric Corporation (43.47% Owned)	$	56	$	58	$	105	$	113
Sweeny Cogeneration Limited Partnership (50% Owned)		29		28		59		62
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)		8		8		17		15
AEP Consolidated Revenues – Utility Operations:								
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned)		(4)		-		(4)		-

Reclassifications

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

On our 2006 Condensed Consolidated Statement of Income, we reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. These reclassifications totaled $6 million and $13 million for the three and six months ended June 30, 2006, respectively.

In our segment information, we reclassified two subsidiary companies, AEP Texas Commercial & Industrial Retail GP, LLC and AEP Texas Commercial & Industrial Retail LP, from the Utility Operations segment to the Generation and Marketing segment. Combined revenues for these companies totaled $11 million and $16 million for the three and six months ended June 30, 2006, respectively. As a result, on our 2006 Condensed Consolidated Statement of Income, we reclassified these revenues from Utility Operations to Other.

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

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented in 2007 and standards issued but not implemented that we have determined relate to our operations.

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. We expect that the adoption of this standard will impact MTM valuations of certain contracts, but we are unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. We will adopt SFAS 157 effective January 1, 2008.

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

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

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. If we elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. We will adopt SFAS

159 effective January 1, 2008. We expect the adoption of this standard to have an immaterial impact on our financial statements.

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

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

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

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

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. We adopted FIN 48 effective January 1, 2007, with an unfavorable adjustment to retained earnings of $17 million.

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

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

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

Future Accounting Changes

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

EXTRAORDINARY ITEM

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

3. RATE MATTERS

As discussed in our 2006 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2006 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations, cash flows and possibly financial condition. The following discusses ratemaking developments in 2007 and updates the 2006 Annual Report.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs. Pursuant to the RSPs, CSPCo and OPCo implemented these proposed increases effective with the first billing cycle in May 2007. These increases are subject to refund until the PUCO issues a final order in the matter. The PUCO staff and intervenors have proposed disallowances. The revenues collected, subject to refund, are immaterial through June 30, 2007. Management is unable to determine the impact, if any, of potential refunds or rider reductions on future results of operations and cash flows. The hearing is completed and initial post-hearing and reply briefs have been filed. A final order is expected in late third quarter or early fourth quarter of 2007.

In March 2007, CSPCo filed an application under the 4% provision of the RSP to adjust the Power Acquisition Rider (PAR) which was authorized in 2005 by the PUCO in connection with CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio and a new purchase power contract to serve the load. The PUCO approved the requested increase in the PAR, which is expected to increase CSPCo's revenues by $22 million and $38 million for 2007 and 2008, respectively.

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

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio regarding potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals

As provided in the restructuring settlement agreement approved by the PUCO in 2000, CSPCo and OPCo established regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general base rate filing which changes distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next base rate filing to change distribution rates after the end of the RSP period of December 31, 2008. Through June 30, 2007, CSPCo and OPCo incurred $51 million and $52 million, respectively, of such costs and established regulatory assets of $25 million and $26 million, respectively, for such costs. CSPCo and OPCo each have not recognized $6 million of equity carrying costs, which are recognizable when collected. In 2007, CSPCo and OPCo incurred $2 million each of such costs and established regulatory assets of $1 million each for such costs. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure to recover such costs will have an adverse effect on results of operations and cash flows.

Ohio IGCC Plant

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

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. Through June 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered. As of June 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all amounts collected for pre-construction costs, associated with items that may be utilized in IGCC projects to be built by AEP at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

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

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant are $2.2 billion. CSPCo and OPCo may need to request an extension to the 5 year start of construction requirement if the commencement of construction is delayed beyond 2011. In July 2007, CSPCo and OPCo filed a status report with the PUCO referencing APCo's IGCC West Virginia filing. See the "West Virginia IGCC Plant" section within West Virginia Rate Matters of this note.

Distribution Reliability Plan

In January 2006, CSPCo and OPCo initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, CSPCo and OPCo filed a proposed enhanced reliability plan. The plan contemplated CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen month period beginning July 2007. In January 2007, the Ohio Consumers' Counsel filed testimony, which argued that CSPCo and OPCo should be required to improve distribution service reliability with funds from their existing rates.

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

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, under a PUCO-encouraged settlement agreement. The settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH to be paid by Ormet for power and a PUCO-approved market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is insufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, CSPCo and OPCo submitted a market price of $47.69 per MWH for 2007, which was approved by the PUCO in June 2007. CSPCo and OPCo have each amortized $3 million of their Ohio Franchise Tax phase-out tax regulatory liability to income through June 30, 2007. If the PUCO approves a lower-than-market price in 2008, it could have an adverse effect on future results of operations and cash flows. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo off-system sales margins, which could have an adverse effect on future results of operations and cash flows.

Texas Rate Matters

TCC TEXAS RESTRUCTURING

Texas District Court Appeal Proceedings

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

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

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

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

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

OTHER TEXAS RESTRUCTURING MATTERS

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's 2006 true-up and securitization orders, the PUCT reduced net regulatory assets and the amount to be securitized by $51 million related to the present value of ADITC and by $10 million related to EDFIT associated with TCC's generation assets for a total reduction of $61 million.

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

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates $104 million as of June 30, 2007, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a nonappealable order. Management intends to continue its efforts to work with the PUCT to avoid a normalization violation that would adversely affect future results of operations and cash flows.

TCC and TNC Deferred Fuel

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

In 2006, the Federal District Court issued orders precluding the PUCT from enforcing the off-system sales reallocation portion of its ruling in the final TNC and TCC fuel reconciliation proceedings. The Federal court ruled, in both cases, that the FERC, not the PUCT, has jurisdiction over the allocation. The PUCT appealed both Federal District Court decisions to the United States Court of Appeals. In TNC's case, the Court of Appeals affirmed the District Court's decision. In April 2007, the PUCT petitioned the United States Supreme Court for a review of the Court of Appeals' order. If the PUCT's appeals are ultimately unsuccessful, TCC and TNC could record income of $16 million and $8 million, respectively, related to the reversal of the previously-recorded fuel over-recovery regulatory liabilities related to the reallocation of off-system sales margins to TCC and TNC.

If the PUCT is unsuccessful in the federal court system, it or another interested party may file a complaint at the FERC to address the allocation issue. If a complaint at the FERC results in the PUCT's decisions being adopted by the FERC, there could be an adverse effect on results of operations and cash flows. An unfavorable FERC ruling may result in a retroactive reallocation of off-system sales margins from AEP East companies to AEP West companies under the then-existing SIA allocation method. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts reallocated to the West companies from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits. Although management cannot predict the ultimate outcome of this federal litigation, management believes that the allocations were in accordance with the then-existing FERC-approved SIA and that it should not be expected to reallocate additional off-system sales margins to the West companies including TCC and TNC.

In January 2007, TCC began refunding as part of the CTC rate rider credit, $149 million of its $165 million over-recovered deferred fuel regulatory liability. The remaining $16 million refund related to the favorable Federal District Court order has been deferred pending the outcome of the federal court appeal and would be subject to refund only upon a successful appeal by the PUCT.

TCC Excess Earnings

In 2005, the Texas Court of Appeals issued a decision finding that the PUCT's prior order from the unbundled cost of service case requiring TCC to refund excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. TCC refunded $55 million of excess earnings, including interest, of which $30 million went to the affiliated REP. In November 2005, the PUCT filed a petition for review with the Supreme Court of Texas seeking reversal of the Texas Court of Appeals' decision. In June 2007, the Supreme Court of Texas declined the petition for review. Certain intervenors have contended in the stranded cost proceeding that a reduction to stranded cost is required, but a surcharge of unlawfully-refunded amounts is unnecessary. TCC believes it has properly reflected the effects of the Court of Appeals' ruling and the PUCT's rules on stranded costs. However, a ruling in favor of the intervenor's position could have a material adverse effect on future results of operations and cash flow.

TCC Oklaunion Refund

In 2005, TCC filed a special request with the PUCT allowing TCC to file its true-up proceeding before it had completed the sale of its share of the Oklaunion power plant. TCC agreed to provide customers the net economic benefit related to its continued ownership of the Oklaunion power plant until the sale closed. TCC also agreed to reduce stranded costs in the event the Oklaunion power plant sales price increased. In June 2007, TCC filed with the PUCT reporting no change in the sales price and to include the net economic benefit from the operation of the Oklaunion power plant in the CTC credit rider. As of June 30, 2007, TCC has recorded a $3 million regulatory liability for the net economic benefit related to the operation of the Oklaunion power plant. Management is unable to predict the ultimate outcome of this filing. If the PUCT orders a refund greater than the $3 million recorded liability, it would have an adverse effect on future results of operations and cash flow.

OTHER TEXAS RATE MATTERS

TCC and TNC Energy Delivery Base Rate Filings

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

Beginning in June 2007, TCC implemented an interim base rate increase of $50 million, subject to refund, in accordance with Texas law. In addition, TCC's merger credits were terminated in June 2007, which effectively increased base rates by $20 million on an annual basis. In June 2007, an ALJ issued an interim order affirming the termination of the merger credits. The PUCT affirmed the ALJ ruling. Management has evaluated its exposure to a future refund of revenues being collected, subject to refund, and believes it is recognizing a reasonable amount of such revenues. A decision from the PUCT is expected in the third quarter of 2007. Management is unable to predict the ultimate effect of this filing and any true-up of recognized revenues collected, subject to refund, on future results of operations, cash flows and financial condition.

SWEPCo Fuel Reconciliation – Texas

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations for the three-year reconciliation period ended December 31, 2005. SWEPCo sought, in the proceedings, to include under-recoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The PUCT staff and intervenor disallowances ranged from $10 million to $28 million. In June 2007, an ALJ issued a Proposal for Decision recommending a $17 million disallowance. Results of operations for the second quarter of 2007 were adversely affected by $25 million as a result of reflecting the ALJ's decision. In July 2007, the PUCT orally affirmed the ALJ report. A final order is expected in the third quarter of 2007. Management is unable to predict the ultimate outcome of this proceeding or its additional effect on future results of operations and cash flows**.**

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

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

Virginia Rate Matters

Virginia Restructuring

In April 2004, Virginia enacted legislation that amended the Virginia Electric Utility Restructuring Act extending the transition period to market rates for the generation and supply of electricity, including the extension of capped rates, through December 31, 2010. The legislation provided APCo with specified cost recovery opportunities during the extended capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain unrecovered incremental environmental and reliability costs incurred on and after July 1, 2004. Under the amended restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the amended restructuring law, APCo has the right to defer incremental environmental compliance costs and incremental E&R costs for future recovery, to the extent such costs are not being recovered, and amortizes a portion of such deferrals commensurate with their recovery.

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

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

Virginia Base Rate Case

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including the cost of its investment in environmental equipment and a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which was estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request included $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase that was collected, subject to refund, includes recovery of incremental E&R costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovered through the E&R surcharge mechanism if not recovered through base rates. In October 2006, the Virginia SCC staff filed its direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors recommended base rate increases ranging from $42 million to $112 million. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006.

In March 2007, the Hearing Examiner issued a report recommending a $76 million increase in APCo's base rates and a $45 million credit to the fuel factor for off-system sales margins resulting in a net $31 million recommended rate increase. In May 2007, the Virginia SCC issued a final order approving an overall annual base rate increase of $24 million effective as of October 2006. The final order approved a return on equity of 10.0% and limited forward-looking ratemaking adjustments to June 30, 2006 as opposed to September 30, 2007 as proposed. In addition, the final order excluded a portion of APCo's requested E&R costs in base rates. However, APCo was able to defer unrecovered incremental E&R costs incurred after October 1, 2006 and will recover those costs through the E&R surcharge mechanism. The order also provided for a retroactive annual reduction in depreciation to January 1, 2006 of approximately $11 million per year and a deferral and recovery of ARO costs over 10 years. The final order further provides that off-system sales margins of $101 million be credited to customers through a separate base rate margin rider which is not trued-up to actual margins. The final order did not implement the minimum 25% sharing percentage for off-system sales margins embodied in the new re-regulation legislation, which is effective with the first fuel clause filing after July 1, 2007. This sharing requirement in the new re-regulation legislation also includes a true-up to actual off-system sales margins.

As a result of the final order, APCo's second quarter pretax earnings decreased by approximately $3 million due to a decrease in revenues of $42 million net of a recorded provision for refund and related interest offset by (a) a $15 million net effect from the deferral of unrecovered incremental E&R costs incurred from October 1, 2006 through June 30, 2007 to be collected in a future E&R filing, (b) a $9 million net deferral of ARO costs to be recovered over 10 years and (c) a $15 million retroactive decrease in depreciation expense. In addition to the favorable effect of the base rate increase in the second half of 2007, APCo expects to defer for future recovery unrecovered incremental E&R costs incurred of $20 million to $25 million and reduce depreciation and amortization expense by a net $5 million. APCo will complete the refund by August 2007. APCo's Other Current Liabilities includes accrued refunds of $127 million and $22 million as of June 30, 2007 and December 31, 2006, respectively. Management expects pretax earnings for 2007 to be favorably affected by the ordered May 2007 rate increase.

Virginia E&R Costs Recovery Filing

In July 2007, APCo filed a request with the Virginia SCC seeking recovery over the twelve months beginning December 1, 2007 of approximately $60 million of unrecovered incremental E&R costs inclusive of carrying costs thereon incurred from October 1, 2005 through September 30, 2006. APCo will file for recovery in 2008 of E&R cost deferrals incurred and recorded after September 30, 2006.

Virginia Fuel Clause Filing

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

West Virginia IGCC Plant

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

West Virginia Rate Matters

APCo and WPCo ENEC Filing

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

West Virginia IGCC Plant

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

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

Indiana Rate Matters

Indiana Depreciation Study Filing

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counsel (OUCC) that would provide direct benefits to I&M's customers if new lower depreciation rates were approved by the IURC. The direct benefits would include a $5 million credit to fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement were to be approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended and the settlement agreed to a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately $69 million reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers' electric service rates. As proposed, the book depreciation reduction would increase earnings, but would not impact cash flows until rates are revised. Base and fuel rates were frozen in Indiana through June 30, 2007. The IURC held a public hearing in April 2007. In June 2007, the IURC approved the settlement agreement, but modified the effective date of the new depreciation rates upon the filing by I&M of a general rate petition. See "Indiana Rate Filing" section below. On June 19, 2007, I&M and the OUCC notified the IURC the parties would accept the modification to the settlement agreement and I&M filed its rate petition.

The settlement agreement modification reduced book depreciation rates, which will result in an increase of $37 million in pretax earnings for the period June 19, 2007 to December 31, 2007. The $37 million increase is partially offset by a $5 million regulatory liability, recorded in June 2007, to provide for the agreed-upon fuel credit. I&M's approved depreciation rates are subject to further review in the general rate case. I&M's earnings will continue to benefit until the base rates are revised to include lower depreciation rates, at which time cash flows will be adversely affected. Management expects new base rates will become effective in late 2008 or early 2009.

Indiana Rate Filing

In June 2007, I&M filed a rate notification petition with the IURC regarding its intent to file for a base rate increase with a proposed test year ended September 30, 2007. The petition indicated, among other things, the filing would include a request to implement rate tracker mechanisms for certain variable components of the cost of service including AEP Power Pool capacity settlements, PJM RTO costs, reliability enhancement costs, DSM/energy efficiency program costs, off-system sales margins, and net environmental compliance costs. The petition requests the IURC to approve the test year period and the inclusion of the above trackers in the rate filing. Management expects to file the case in late 2007 or early 2008 with a decision expected in late 2008 or early 2009.

Indiana Rate Cap

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

Kentucky Rate Matters

Environmental Surcharge Filing

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

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

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

Oklahoma Rate Matters

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

In 2002, PSO under-recovered $44 million of purchased power costs through its fuel clause resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with the proposed reallocation of off-system sales margins of $27 million to $37 million and with $9 million of purchased power reallocation attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had been refunded, thus removing that issue from its recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling. In April 2007, the PUCT petitioned the United States Supreme Court for a review of the Court of Appeal's order.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its right to recover its under-recovered fuel balance. Management believes that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins to PSO is improper, which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. However, to date, there has been no claim asserted at the FERC that AEP deviated from the FERC approved allocation methodologies, but even if one were asserted, management believes that the OCC or another party would not prevail.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and management expects a recommendation from the ALJ in the second half of 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. PSO filed its testimony in June 2007 covering the year 2005.

In May 2007, PSO filed an application to adjust its fuel/purchase power rates. In the filing, PSO netted the $42 million of under-recovered pre-2002 reallocated purchased power costs against their current $48 million over-recovered fuel balance. In oral discussions, the OCC staff did not oppose the netting of the balances. The $6 million net over-recovered fuel/purchased power cost deferral balance will be refunded over the twelve month period beginning June 2007. To date, no party has objected to the offset.

Management cannot predict the outcome of the pending fuel and purchased power costs and prudence reviews, planned future reviews or the current fuel adjustment clause filing, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the pre-2002 reallocation of purchased power costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

Oklahoma Rate Filing

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

In March 2007, the OCC staff and various intervenors filed testimony. The recommendations were base rate reductions that ranged from $18 million to $52 million. The recommended returns on equity ranged from 9.25% to 10.09%. These recommendations included reductions in depreciation expense of approximately $25 million, which has no earnings impact. The OCC staff filed testimony supporting a formula rate plan, generally similar to the one proposed by PSO. In April 2007, PSO filed rebuttal testimony regarding various issues raised by the OCC staff and the intervenors. In connection with the filing of rebuttal testimony, PSO reduced its base rate request by $2 million. The ALJ issued a report in May 2007 recommending a 10.5% return on equity but did not compute an overall revenue requirement. The ALJ's report did not recommend adopting a formula rate plan, but did recommend recovery through a rider of certain generation and transmission projects' financing costs during construction. However, the report also contained an alternative recommendation that the OCC could delay a decision on the rider and take up this issue in PSO's application seeking regulatory approval of the coal-fueled generating unit. The OCC's discussions during deliberations have centered around a return on equity of 9.75%. PSO implemented interim rates, subject to refund, for residential customers beginning July 2007. The interim rate implements a key provision of the rate case on which there seems to be agreement at the OCC, and is estimated to increase revenues by approximately $4 million in 2007 and $9 million on an annual basis. Other components of the rate case will be implemented once the OCC issues a final order, which is expected in early August 2007.

Management is unable to predict the final outcome of these proceedings. However, if rates are not increased in an amount sufficient to recover expected unavoidable cost increases, future results of operations, cash flows and possibly financial condition could be adversely affected.

Lawton and Peaking Generation Settlement Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration, L.L.C. (Lawton) seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court (the Court). In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Court issued a decision 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. Hearings were held on the remanded issues in April and May 2006.

In April 2007, all parties in the case filed a settlement agreement with the OCC resolving all issues. The OCC approved the settlement agreement in April 2007. The OCC staff, the Attorney General, the Oklahoma Industrial Energy Consumers and Lawton Cogeneration, L.L.C supported this settlement agreement. The settlement agreement provides for a purchase fee of $35 million to be paid by PSO to Lawton and for Lawton to provide, at PSO's direction, all rights to the Lawton Cogeneration Facility including permits, options and engineering studies. PSO paid the $35 million purchase fee in June 2007 and recorded the purchase fee as a regulatory asset and will recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service. PSO expects these units will have a substantially lower plant-in-service cost than the proposed Lawton Cogeneration Facility. PSO may request approval from the OCC for recovery of costs exceeding the cost cap if special circumstances occur necessitating a higher level of costs. Such costs will continue to be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. Under the settlement, PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units. Once the cost recovery for the new peaking units begins in mid-2008, PSO expects annual revenues of an estimated $36 million related to cost recovery of the peaking units and the purchase fee.

Louisiana Rate Matters

Louisiana Compliance Filing

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

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

FERC Rate Matters

Transmission Rate Proceedings at the FERC

The FERC PJM Regional Transmission Rate Proceeding

At AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposed and supported a new

PJM rate regime generally referred to as a Highway/Byway rate design.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in net revenues per year for AEP from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV in the Highway rate, which would have produced lower net revenues for AEP than the AEP/AP proposal.
- In another competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would also have produced lower net revenues for AEP than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting phase-in of a PJM-wide flat rate or "Postage Stamp" type of rate design that would socialize the cost of all transmission facilities. The proposed rate design would have initially produced much lower net transmission revenues for AEP than the AEP/AP proposal, but could produce slightly higher net revenues when fully phased in.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favored continuation of the existing PJM rate design which provides AEP with no compensation for through and out traffic on its east zone transmission system. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC to be just and reasonable alternatives. The ALJ also found FERC staff's proposed Postage Stamp rate to be just and reasonable and recommended that it be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the new regional design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP than the AEP/AP proposal. However, the proposed phase-in of Postage Stamp rates would delay the full favorable impact of those new regional rates until about 2012.

AEP filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. AEP argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest.

Since the FERC's decision in 2005 to cease through-and-out rates and replace them temporarily with SECA rates which ceased on April 1, 2006, the AEP East companies increased their retail rates in all states except Indiana and Michigan to recover lost through-and-out transmission service (T&O) and SECA revenues.

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

The AEP East companies presently recover from retail customers approximately 85% of the lost T&O/SECA transmission revenues of $128 million a year. Future results of operations, cash flows and financial condition will continue to be adversely affected in Indiana and Michigan until these lost T&O/SECA transmission revenues are recovered in retail rates.

SECA Revenue Subject to Refund

The AEP East companies ceased collecting T&O revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. Approximately $19 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of AEP's SECA customers. The AEP East companies reached settlements with certain SECA customers related to approximately $69 million of such revenues for a net refund of $3 million. The AEP East companies are in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and will consume about $7 million of the reserves for refunds, leaving approximately $115 million of contested SECA revenues and $30 million of refund reserves. If the ALJ's initial decision were upheld in its entirety, it would disallow approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on recent settlement experience and the expectation that most of the $115 million of unsettled SECA revenues will be settled, management believes that the remaining reserve will be adequate.

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

PSO and SWEPCo SPP Transmission Formula Rate Filing

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

PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. FERC could suspend the effective date until February 1, 2008. The primary impact of the filed revised tariff will be an increase in network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP Zone. If the proposed formula rate and requested return on equity are approved, the 2008 network transmission service revenues from nonaffiliates will increase by approximately $10 million compared to the revenues that would result from the presently approved network transmission rate. PSO and SWEPCo take service under the same rate, and will also incur the increased OATT rates resulting from the filing, but will receive corresponding revenue to offset the increase. This filing will not directly impact retail rates.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

GUARANTEES

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

Letters of Credit

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At June 30, 2007, the maximum future payments for all the LOCs were approximately $27 million with maturities ranging from July 2007 to July 2008.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of June 30, 2007, SWEPCo has collected approximately $31 million through a rider for final mine closure costs, of which approximately $14 million is recorded in Deferred Credits and Other and approximately $17 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sales agreements is discussed in the 2006 Annual Report, "Dispositions" section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.9 billion (approximately $1 billion relates to the Bank of America (BOA) litigation, see "Enron Bankruptcy" section of this note). There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At June 30, 2007, the maximum potential loss for these lease agreements was approximately $59 million ($38 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

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

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

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

Under the CAA, if a plant undertakes a major modification that 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 routine maintenance, replacement of degraded equipment or failed component or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

Cases are pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer, and Stuart Stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. In April 2007, the Supreme Court denied the petition for review. The Federal EPA also proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

On April 2, 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo in U.S. District Court for the Southern District of Ohio, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of our NSR proceedings. The court that heard our trial on liability issues will likely issue its decision during the third quarter of 2007. A bench trial on remedy issues, if necessary, is likely to begin in 2007.

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

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the third quarter of 2007.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation limiting the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007 removing the heat input references from the Welsh permit and clarifying the sulfur content of fuels burned at the plant is limited to 0.5% on an as-received basis. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion.

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

Carbon Dioxide (CO_2) Public Nuisance Claims

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

TEM Litigation

OPCo agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement dated

November 15, 2000 (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

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

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

In May 2007, the United States Court of Appeals for the Second Circuit ruled that the lower court was correct in finding that TEM breached the PPA and we did not breach the PPA. It also ruled that the lower court applied an incorrect standard in denying us any damages for TEM's breach of the 20-year term of the PPA holding that we are entitled to the benefit of our bargain and that the trial court must determine our damages. The Court of Appeals vacated our $123 million judgment for damages against TEM related to replacement products and remanded the issue for further proceedings.

Enron Bankruptcy

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

After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. In 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage facility. In 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. In August 2006, the Court of Appeals for the First District of Texas vacated the trial court's judgment and dismissed the BOA Syndicate's case. The BOA Syndicate did not seek review of this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL's motion to have the case assigned to the judge who heard the case originally was granted. HPL intends to defend against any renewed claims by BOA.

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

In February 2007, the Judge in the New York action, after hearing oral argument on the motions for summary judgment, made a series of oral "informal findings" and submitted a written memorandum to the parties' counsel. In the memorandum to counsel, the Judge stated that he was denying several of AEP's motions for partial summary judgment and granting several of BOA motions for summary judgment. The substantive matters left open for further proceedings include the issue of the nature of the gas subject to BOA security interest and the value of that interest. The Judge stated that the memorandum to counsel is not an opinion or an order, and that no opinion or order will be issued until all motions pending before the Court have been decided. The Judge heard additional arguments on the summary judgment motions in March 2007. At this time we are unable to predict how the Judge will rule on the pending motions due to the complexity of those issues and the parties' disagreement over each issue. If the Judge issues a judgment directing AEP to pay an amount in excess of the gain on the sale of HPL described below and if AEP is unsuccessful in having the judgment reversed or modified, the judgment could have a material adverse effect on the results of operations, cash flows, and possibly financial condition.

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

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination and recognition of the gain on the sale are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter. The deferred gain, estimated to be $382 million and $380 million at June 30, 2007 and December 31, 2006, respectively, is included in Deferred Credits and Other on our Condensed Consolidated Balance Sheets.

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

Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in Federal District Court, Columbus, Ohio. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2006, the plaintiffs filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. Briefing of this appeal was completed in December 2006. The Court of Appeals heard oral argument in July 2007. We intend to continue to defend against these claims.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were filed in California. In addition, a number of other cases were filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases were transferred to the United States District Court for the District of Nevada but subsequently were remanded to California state court. In 2005 and subsequently, the judge in Nevada dismissed a number of the remaining cases on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. In July 2007, the judge in the California cases stayed those proceedings pending a decision by the Ninth Circuit in the federal cases. We will continue to defend each case where an AEP company is a defendant.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that we sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. An ALJ recommended rejection of the complaint, holding that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. In May 2007, we, along with other sellers involved in the case, sought review of the Ninth Circuit's decision by the U.S. Supreme Court. The Solicitor General of the United States has asked the Supreme Court for an extension of time, until August 6, 2007, to respond to the petitions for review. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

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

ACQUISITIONS

2007

Darby Electric Generating Station (Utility Operations segment)

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

Lawrenceburg Generating Station (Utility Operations segment)

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

2006

None

DISPOSITIONS

2007

Texas Plants – Oklaunion Power Station (Utility Operations segment)

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

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

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

Texas REPs (Utility Operations Segment)

As part of the purchase-and-sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. We received $20 million and $70 million payments in 2007 and 2006, respectively, for our share in earnings. These payments are reflected in Gain/Loss on Disposition of Assets, Net on our Condensed Consolidated Statements of Income. The payment we received in 2007 was the final payment under the earnings sharing agreement.

2006

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

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

DISCONTINUED OPERATIONS

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

Three Months Ended June 30,	U.K. Generation (a) (in millions)
2007 Revenue	$ -
2007 Pretax Income	3
2007 Earnings, Net of Tax	2
2006 Revenue	$ -
2006 Pretax Income	4
2006 Earnings, Net of Tax	3

U.K.

Six Months Ended June 30,	Generation (a) (in millions)
2007 Revenue	$ -
2007 Pretax Income	3
2007 Earnings, Net of Tax	2
2006 Revenue	$ -
2006 Pretax Income	9
2006 Earnings, Net of Tax	6

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

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the six months ended June 30, 2007 and 2006.

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

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

Assets Held for Sale were as follows:

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

6. <u>BENEFIT PLANS</u>

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

Components of Net Periodic Benefit Cost

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

Other Postretirement

	Pension Plans		Benefit Plans	
	2007	2006	2007	2006
Three Months Ended June 30, 2007 and 2006	(in millions)			
Service Cost	$ 23	$ 24	$ 11	$ 10
Interest Cost	57	57	26	25
Expected Return on Plan Assets	(82)	(83)	(26)	(23)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	14	19	3	5
Net Periodic Benefit Cost	$ 12	$ 17	$ 21	$ 24

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Six Months Ended June 30, 2007 and 2006	(in millions)			
Service Cost	$ 47	$ 48	$ 21	$ 20
Interest Cost	116	114	52	50
Expected Return on Plan Assets	(167)	(166)	(52)	(46)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	29	39	6	10
Net Periodic Benefit Cost	$ 25	$ 35	$ 41	$ 48

7. BUSINESS SEGMENTS

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

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

Utility Operations

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

MEMCO Operations

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

Generation and Marketing

- IPPs, wind farms and marketing and risk management activities primarily in ERCOT.

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

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

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

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

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended June 30, 2007						
Revenues from:						
External Customers	$ 2,818	$ 116	$ 218	$ (6)	$ -	$ 3,146
Other Operating Segments	136	3	(113)	12	(38)	-
Total Revenues	$ 2,954	$ 119	$ 105	$ 6	$ (38)	$ 3,146
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 238	$ 7	$ 15	$ (3)	$ -	$ 257
Discontinued Operations, Net of Tax	-	-	-	2	-	2
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income (Loss)	$ 159	$ 7	$ 15	$ (1)	$ -	$ 180

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended June 30, 2006						
Revenues from:						
External Customers	$ 2,799	$ 117	$ 20	$ -	$ -	$ 2,936
Other Operating Segments	(3)	2	-	15	(14)	-
Total Revenues	$ 2,796	$ 119	$ 20	$ 15	$ (14)	$ 2,936
Income (Loss) Before Discontinued Operations	$ 159	$ 14	$ 2	$ (3)	$ -	$ 172
Discontinued Operations, Net of Tax	-	-	-	3	-	3
Net Income	$ 159	$ 14	$ 2	$ -	$ -	$ 175

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

	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Six Months Ended June 30, 2007						
Revenues from:						
External Customers	$ 5,704	$ 233	$ 333	$ 45	$ -	$ 6,315
Other Operating Segments	283	6	(186)	(33)	(70)	-
Total Revenues	$ 5,987	$ 239	$ 147	$ 12	$ (70)	$ 6,315
Income Before Discontinued Operations and Extraordinary Loss	$ 491	$ 22	$ 14	$ 1	$ -	$ 528
Discontinued Operations, Net of Tax	-	-	-	2	-	2
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income	$ 412	$ 22	$ 14	$ 3	$ -	$ 451

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Six Months Ended June 30, 2006						
Revenues from:						
External Customers	$ 5,781	$ 233	$ 33	$ (3)	$ -	$ 6,044
Other Operating Segments	(19)	5	-	37	(23)	-
Total Revenues	$ 5,762	$ 238	$ 33	$ 34	$ (23)	$ 6,044
Income (Loss) Before Discontinued Operations	$ 524	$ 35	$ 6	$ (15)	$ -	$ 550
Discontinued Operations, Net of Tax	-	-	-	6	-	6
Net Income (Loss)	$ 524	$ 35	$ 6	$ (9)	$ -	$ 556

		Nonutility Operations				
June 30, 2007	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 43,794	$ 241	$ 566	$ 36	$ (237)(b)	$ 44,400
Accumulated Depreciation and Amortization	15,781	55	97	6	(6)(b)	15,933
Total Property, Plant and Equipment – Net	$ 28,013	$ 186	$ 469	$ 30	$ (231)(b)	$ 28,467
Total Assets	$ 38,109	$ 307	$ 752	$ 11,901	$ (11,875)(c)	$ 39,193

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

(a) All Other includes:

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

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

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

8. INCOME TAXES

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

Audit Status

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

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

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

FIN 48 Adoption

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

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

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

Michigan Tax Restructuring

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

We are in the process of evaluating the impact of the MBT Act. It is expected that the application of the MBT Act will not have a material effect on our results of operation, cash flows or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	June 30, 2007	December 31, 2006
	(in millions)	
Senior Unsecured Notes	$ 9,399	$ 8,653
Pollution Control Bonds	2,153	1,950
First Mortgage Bonds	90	90
Defeased First Mortgage Bonds (a)	19	27
Notes Payable	312	337
Securitization Bonds	2,303	2,335

Notes Payable To Trust		113		113
Spent Nuclear Fuel Obligation (b)		253		247
Other Long-term Debt		3		2
Unamortized Discount (net)		(57)		(56)
Total Long-term Debt Outstanding		14,588		13,698
Less Portion Due Within One Year		1,521		1,269
Long-term Portion	$	13,067	$	12,429

(a) In May 2004, cash and treasury securities were deposited with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of $19 million at both June 30, 2007 and December 31, 2006. Trust Fund Assets related to this obligation of $23 million and $2 million at June 30, 2007 and December 31, 2006, respectively, are included in Other Temporary Investments and $21 million at December 31, 2006, is included in Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. In December 2005, cash and treasury securities were deposited with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond was retired in June 2007. The defeased TNC First Mortgage Bond had a balance of $8 million at December 31, 2006. Trust fund assets related to this obligation of $9 million at December 31, 2006, are included in Other Temporary Investments on our Condensed Consolidated Balance Sheet. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust Fund assets related to this obligation of $277 million and $274 million at June 30, 2007 and December 31, 2006, respectively, are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

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

Company	**Type of Debt**		**Principal Amount (in millions)**	**Interest Rate (%)**	**Due Date**
Issuances:					
APCo	Pollution Control Bonds	$	75	Variable	2037
OPCo	Pollution Control Bonds		65	4.90	2037
OPCo	Senior Unsecured Notes		400	Variable	2010
PSO	Pollution Control Bonds		13	4.45	2020
SWEPCo	Senior Unsecured Notes		250	5.55	2017
Non-Registrant:					
AEGCo	Senior Unsecured Notes		220	6.33	2037
TCC	Pollution Control Bonds		6	4.45	2020
TNC	Pollution Control Bonds		44	4.45	2020
Total Issuances		$	1,073(a)		

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

(a)

Amount indicated on statement of cash flows of $1,064 million is net of issuance costs and unamortized premium or discount.

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

Company	Type of Debt		Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
APCo	Senior Unsecured Notes	$	125	Variable	2007
OPCo	Notes Payable		3	6.81	2008
OPCo	Notes Payable		6	6.27	2009
SWEPCo	Notes Payable		3	4.47	2011
SWEPCo	Notes Payable		4	6.36	2007
SWEPCo	Notes Payable		2	Variable	2008
Non-Registrant:					
AEP Subsidiaries	Notes Payable		3	Variable	2017
CSW Energy, Inc.	Notes Payable		4	5.88	2011
TCC	Securitization Bonds		32	5.01	2008
TNC	Defeased First Mortgage Bonds		8	7.75	2007
Total Retirements and Principal Payments		$	190		

In July 2007, KPCo retired $125 million of 5.50% Senior Unsecured Notes due in 2007.

In July 2007, PSO redeemed $13 million of 6.00% Pollution Control Bonds due in 2020.

In July 2007, TCC redeemed $6 million of 6.00% Pollution Control Bonds due in 2020.

In July 2007, TNC redeemed $44 million of 6.00% Pollution Control Bonds due in 2020.

Short-term Debt

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

	June 30, 2007			December 31, 2006		
Type of Debt		**Outstanding Amount (in millions)**	**Interest Rate**		**Outstanding Amount (in millions)**	**Interest Rate**
Commercial Paper – AEP	$	416	5.40%(a)	$	-	-
Commercial Paper – JMG (b)		-	-		1	5.56%
Line of Credit – Sabine (c)		22	6.20%		17	6.38%
Total	$	438		$	18	

(a) Weighted average rate.

(b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce available liquidity under AEP's credit facilities.

(c) Sabine is consolidated under FIN 46. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

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

Dividend Restrictions

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

Sale of Receivables – AEP Credit

In July 2007, we extended AEP Credit's sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million from a bank conduit to purchase receivables from AEP Credit. This agreement will expire in November 2007. We intend to renew or replace this agreement.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

Reconciliation of Second Quarter of 2006 to Second Quarter of 2007
Net Income Before Extraordinary Loss
(in millions)

Second Quarter of 2006		$ 10
Changes in Gross Margin:		
Retail Margins	(39)	
Off-system Sales	18	
Transmission Revenues	7	
Other	3	
Total Change in Gross Margin		(11)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(3)	
Depreciation and Amortization	17	
Carrying Costs Income	3	
Other Income, Net	(5)	
Interest Expense	(13)	
Total Change in Operating Expenses and Other		(1)
Income Tax Expense		5
Second Quarter of 2007		$ 3

Net Income Before Extraordinary Loss decreased $7 million to $3 million. The key drivers of the decrease were an $11 million decrease in Gross Margin, partially offset by a $5 million decrease in Income Tax Expense.

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

- Retail Margins decreased $39 million in comparison to 2006 primarily due to:
  - A $38 million decrease in retail revenues primarily related to APCo's Virginia base rate case which includes a second quarter 2007 provision for revenue refund as a result of the final order offset by the new rates implemented. See "Virginia Base Rate Case" section of Note 3.
  - A $24 million increase in capacity settlement expenses under the Interconnection Agreement reflecting APCo's new peak demand in February 2007.
  - A $12 million decrease in revenues related to financial transmission rights, net of congestion, primarily due to fewer transmission constraints in the PJM market.

These decreases were partially offset by:

- A $16 million increase in revenues related to the Expanded Net Energy Cost (ENEC) mechanism with West Virginia retail customers. The mechanism was reinstated in West Virginia effective July 1, 2006 in conjunction with the West Virginia rate case.
- An $18 million increase in retail sales primarily due to increased demand in the residential class associated with favorable weather conditions. Cooling degree days increased approximately 54%.

- Margins from Off-system Sales increased $18 million primarily due to higher power prices in the east, higher trading margins, and an increase in APCo's allocated share of off-system sales revenues due to its new peak.
- Transmission Revenues increased $7 million primarily due to a provision recorded in the second quarter of 2006 related to potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $3 million primarily due to the following:
  - A $4 million increase in steam maintenance expenses resulting from 2007 planned outages at the Amos and Glen Lyn plants.
  - A $3 million increase in customer accounts and services expense primarily related to an increase in uncollectible accounts under a contract dispute.

  These increases were offset by:
  - A $5 million decrease in expenses related to the AEP Transmission Equalization Agreement due to the addition of the Wyoming-Jacksons Ferry 765 kV line which was energized and placed into service in June 2006.
- Depreciation and Amortization expenses decreased $17 million primarily due to lower Virginia depreciation rates implemented retroactively to January 2006 for $15 million and lower amortization resulting from a net deferral of $9 million in ARO costs as ordered in APCo's Virginia base rate case. These decreases were partially offset by the amortization of carrying charges and depreciation expense of $3 million that are being collected through the E&R surcharge mechanism. In addition, an increase in depreciation expense was also related to the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006, and the Mountaineer scrubber, which was placed in service in February 2007.
- Carrying Costs Income increased $3 million related to carrying costs associated with the E&R case.
- Other Income, Net decreased $5 million primarily due to a $2 million decrease in interest income from the Utility Money Pool and a $2 million decrease in AFUDC resulting from a lower construction work in progress (CWIP) balance after the Wyoming-Jacksons Ferry 765 kv line and the Mountaineer scrubber were placed into service.
- Interest Expense increased $13 million primarily due to a $6 million decrease in allowance for borrowed funds used for construction, a $3 million increase in interest expense from the Utility Money Pool, and a $3 million increase in the interest on the Virginia provision for refund.

Income Taxes

Income Tax Expense decreased $5 million primarily due to a decrease in pretax book income.

<u>Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006</u>

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

Six Months Ended June 30, 2006	$	83
Changes in Gross Margin:		

Retail Margins	(10)	
Off-system Sales	12	
Transmission Revenues	(4)	
Other	4	
Total Change in Gross Margin		2
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(8)	
Depreciation and Amortization	7	
Taxes Other Than Income Taxes	2	
Other Income, Net	(5)	
Interest Expense	(15)	
Total Change in Operating Expenses and Other		(19)
Income Tax Expense		8
Six Months Ended June 30, 2007		$ 74

Net Income Before Extraordinary Loss decreased $9 million to $74 million in 2007. The key drivers of the decrease were a $19 million increase in Operating Expenses and Other, partially offset by an $8 million decrease in Income Tax Expense.

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

- Retail Margins decreased $10 million in comparison to 2006 primarily due to:
  - A $26 million decrease in revenues related to financial transmission rights, net of congestion, primarily due to fewer transmission constraints in the PJM market.
  - A $26 million increase in capacity settlement expenses under the Interconnection Agreement reflecting APCo's new peak demand in February 2007.

  These decreases were partially offset by:
  - A $7 million increase in revenues related to the ENEC mechanism with West Virginia retail customers. The mechanism was reinstated in West Virginia effective July 1, 2006 in conjunction with the West Virginia rate case.
  - A $27 million increase in retail sales primarily due to increased demand in the residential class associated with favorable weather conditions. Heating degree days increased approximately 27% and Cooling degree days increased approximately 62%.
  - A $9 million increase in municipal and cooperative revenues primarily due to the addition of the Blue Ridge Power Agency customers.
- Margins from Off-system Sales increased $12 million primarily due to higher power prices in the east, higher trading margins, an increase in APCo's allocated share of off-system sales revenues due to its new peak, and a change in the allocation of off-system sales margins under the SIA effective April 1, 2006.
- Transmission Revenues decreased $4 million primarily due to the elimination of SECA revenues of $13 million as of April 1, 2006. See "Transmission Rate Proceedings at the FERC" section of Note 3. This decrease was partially offset by a provision recorded in the second quarter of 2006 related to potential SECA refunds and additional transmission revenues relating to dedicated energy sales of $2 million.
- Other revenue increased $4 primarily due to the reversal of previously deferred gains on sales of allowances associated with the E&R case.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $8 million primarily due to the following:
  - A $4 million increase in steam maintenance expenses resulting from 2007 planned outages at the Amos and Glen Lyn plants.
  - A $6 million increase in expenses for distribution line right-of-way clearing.
  - A $4 million increase in uncollectible and factored accounts receivable expense.
  - An $8 million increase in employee related and various other operational expenses.

  These increases were partially offset by:
  - A $14 million decrease in expenses related to the AEP Transmission Equalization Agreement due to the addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed into service in June 2006.
- Depreciation and Amortization expenses decreased $7 million primarily due to lower Virginia depreciation rates implemented retroactively to January 2006 for $15 million and lower amortization resulting from a net deferral of $9 million in ARO costs as ordered in APCo's Virginia base rate case. These decreases were partially offset by the amortization of carrying charges and depreciation expense of $13 million that are being collected through the E&R surcharges. In addition, an increase in depreciation expense was also related to the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006, and the Mountaineer scrubber, which was placed in service in February 2007.
- Other Income, Net decreased $5 million primarily due to lower interest income from the Utility Money Pool of $2 million and a $2 million decrease in AFUDC resulting from a lower CWIP balance after the Wyoming-Jacksons Ferry 765 kV line and the Mountaineer scrubber were placed into service.
- Interest Expense increased $15 million primarily due to an $8 million increase related to the issuance of $500 million of debt in April 2006 and a $4 million decrease in allowance for borrowed funds used during construction.

Income Taxes

Income Tax Expense decreased $8 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the six months ended June 30, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,318	$ 1,741
Cash Flows From (Used For):		

Operating Activities	265,414	316,970
Investing Activities	(378,985)	(618,920)
Financing Activities	112,605	301,555
Net Decrease in Cash and Cash Equivalents	(966)	(395)
Cash and Cash Equivalents at End of Period	$ 1,352	$ 1,346

Operating Activities

Net Cash Flows From Operating Activities were $265 million in 2007. APCo incurred a Net Loss of $5 million during the period and had noncash expense items of $90 million for Depreciation and Amortization and $79 million for Extraordinary Loss for the Reapplication of Regulatory Accounting for Generation and $105 million for Regulatory Provision related to the Virginia base rate case. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital included no significant items.

Net Cash Flows From Operating Activities were $317 million in 2006. APCo produced Net Income of $83 million during the period and a noncash expense item of $97 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital included two significant items. Accounts Receivable, Net decreased $60 million primarily due to the collection of receivables related to power sales to affiliates, settled litigation and sales on emission allowances. Accrued Taxes, Net increased $42 million related to the lack of federal income tax payments made in 2006.

Investing Activities

Net Cash Flows Used For Investing Activities during 2007 and 2006 primarily reflect construction expenditures of $383 million and $404 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades at power plants for both periods. In 2006, capital projects for transmission expenditures were primarily related to the Wyoming-Jacksons Ferry 765 KV line placed into service in June 2006. Environmental upgrades include the installation of selective catalytic reduction equipment on certain plants and the flue gas desulfurization project at the Amos and Mountaineer plants. In February 2007, environmental upgrades were completed for the Mountaineer plant. For the remainder of 2007, APCo expects construction expenditures to be approximately $281 million. In addition, APCo's investments in the Utility Money Pool increased by $219 million in 2006.

Financing Activities

Net Cash Flows From Financing Activities in 2007 were $113 million primarily due to an increase of $213 million in borrowings from the Utility Money Pool and the issuance of $75 million of Pollution Control Bonds. These increases were partially offset by the retirement of $125 million of Senior Notes and payment of $25 million in dividends on common stock.

Net Cash Flows From Financing Activities were $302 million in 2006. In 2006, APCo issued $500 million in Senior Notes and issued $50 million in Pollution Control Bonds. APCo also retired First Mortgage Bonds of $100 million and repaid short-term borrowings from the Utility Money Pool of $194 million. In addition, APCo received funds of $68 million related to a long-term coal purchase contract amended in March 2006.

Financing Activity

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

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	75,000	Variable	2037

Retirements

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

Liquidity

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

Summary Obligation Information

A summary of contractual obligations is included in the 2006 Annual Report and has not changed significantly from year-end other than the debt issuance and retirement discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

New Generation

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

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

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

July 1, 2007 until such costs are recovered, starting January 1, 2009 as required by the new Virginia Re-regulation legislation.

Virginia Restructuring

In April 2004, Virginia enacted legislation that amended the Virginia Electric Utility Restructuring Act extending the transition period to market rates for the generation and supply of electricity, including the extension of capped rates, through December 31, 2010. The legislation provided APCo with specified cost recovery opportunities during the extended capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain unrecovered incremental environmental and reliability costs incurred on and after July 1, 2004. Under the amended restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the amended restructuring law, APCo has the right to defer incremental environmental compliance costs and incremental E&R costs for future recovery, to the extent such costs are not being recovered, and amortizes a portion of such deferrals commensurate with their recovery.

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

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

Litigation and Regulatory Activity

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the

2006 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. Adverse results in these proceedings have the potential to materially affect results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on APCo.

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 73,123	$ 11,439	$ -	$ 84,562
Noncurrent Assets	84,029	2,919	-	86,948
Total MTM Derivative Contract Assets	157,152	14,358	-	171,510
Current Liabilities	(55,013)	(1,137)	(3,570)	(59,720)
Noncurrent Liabilities	(51,130)	(87)	(7,551)	(58,768)
Total MTM Derivative Contract Liabilities	(106,143)	(1,224)	(11,121)	(118,488)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 51,009	$ 13,134	$ (11,121)	$ 53,022

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2007
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 52,489
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(8,051)
Fair Value of New Contracts at Inception When Entered During the Period (a)	255
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	511
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	4,757
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,048
Total MTM Risk Management Contract Net Assets	51,009
Net Cash Flow & Fair Value Hedge Contracts	13,134

DETM Assignment (d)		(11,121)
Total MTM Risk Management Contract Net Assets at June 30, 2007	$	53,022

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

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

The following table presents:

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

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

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ 4,823	$ (3,624)	$ 163	$ -	$ -	$ -	$ 1,362
Prices Provided by Other External Sources – OTC Broker Quotes (a)	6,824	16,070	12,886	5,714	-	-	41,494
Prices Based on Models and Other Valuation Methods (b)	(401)	(1,510)	1,682	5,485	1,248	1,649	8,153
Total	$ 11,246	$ 10,936	$ 14,731	$ 11,199	$ 1,248	$ 1,649	$ 51,009

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

models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available including values determinable by other third party transactions.

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

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

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

Management uses forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on the Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2006 to June 30, 2007. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2007
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2006	$ 5,332	$ (164)	$ (7,715)	$ (2,547)
Changes in Fair Value	7,980	-	-	7,980
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(4,067)	3	694	(3,370)
Ending Balance in AOCI June 30, 2007	$ 9,245	$ (161)	$ (7,021)	$ 2,063

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $6,737 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this

VaR analysis, at June 30, 2007, a near term typical change in commodity prices is not expected to have a material effect on results of operations, cash flows or financial condition.

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

Six Months Ended June 30, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$475	$2,328	$779	$227	$756	$1,915	$658	$358

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

VaR Associated with Debt Outstanding

Management utilizes a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to exposure to interest rates primarily related to long-term debt with fixed interest rates was $178 million and $153 million at June 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended 2007	Three Months Ended 2006	Six Months Ended 2007	Six Months Ended 2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 499,189	$ 464,058	$ 1,100,735	$ 1,024,051
Sales to AEP Affiliates	55,371	48,608	116,916	120,380
Other	2,850	1,922	5,487	4,598
TOTAL	557,410	514,588	1,223,138	1,149,029
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	164,018	155,240	335,204	322,093
Purchased Electricity for Resale	34,328	29,979	70,278	57,595
Purchased Electricity from AEP Affiliates	144,630	103,457	272,231	225,856
Other Operation	75,125	77,156	142,754	147,057
Maintenance	51,414	46,668	97,167	84,507
Depreciation and Amortization	31,076	48,688	90,236	96,956
Taxes Other Than Income Taxes	22,975	22,799	44,250	45,891
TOTAL	523,566	483,987	1,052,120	979,955
OPERATING INCOME	33,844	30,601	171,018	169,074
Other Income (Expense):				
Interest Income	390	2,814	1,029	3,765
Carrying Costs Income	10,950	7,773	14,116	13,784
Allowance for Equity Funds Used During Construction	1,581	4,083	4,358	6,559
Interest Expense	(44,955)	(31,653)	(76,778)	(61,921)
INCOME BEFORE INCOME TAXES	1,810	13,618	113,743	131,261
Income Tax Expense (Credit)	(1,471)	3,971	40,235	48,020
INCOME BEFORE EXTRAORDINARY LOSS	3,281	9,647	73,508	83,241
Extraordinary Loss – Reapplication of Regulatory Accounting for Generation, Net of Tax	(78,763)	-	(78,763)	-
NET INCOME (LOSS)	(75,482)	9,647	(5,255)	83,241
Preferred Stock Dividend Requirements Including Capital Stock Expense	238	238	476	476
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ (75,720)	$ 9,409	$ (5,731)	$ 82,765

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 260,458	$ 924,837	$ 635,016	$ (16,610)	$ 1,803,701
Common Stock Dividends			(5,000)		(5,000)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense and Other		80	(76)		4
TOTAL					1,798,305
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $9,692				17,998	17,998
NET INCOME			83,241		83,241
TOTAL COMPREHENSIVE INCOME					101,239
JUNE 30, 2006	$ 260,458	$ 924,917	$ 712,781	$ 1,388	$ 1,899,544
DECEMBER 31, 2006	$ 260,458	$ 1,024,994	$ 805,513	$ (54,791)	$ 2,036,174
FIN 48 Adoption, Net of Tax			(2,685)		(2,685)
Common Stock Dividends			(25,000)		(25,000)
Preferred Stock Dividends			(400)		(400)
Capital Stock Expense and Other		76	(76)		-
TOTAL					2,008,089
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,482				4,610	4,610
SFAS 158 Costs Established as a Regulatory Asset Related to the Reapplication of SFAS 71, Net of Tax of $6,055				11,245	11,245
NET LOSS			(5,255)		(5,255)
TOTAL COMPREHENSIVE INCOME					10,600
JUNE 30, 2007	$ 260,458	$ 1,025,070	$ 772,097	$ (38,936)	$ 2,018,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,352	$ 2,318
Accounts Receivable:		
Customers	176,758	180,190
Affiliated Companies	76,139	98,237
Accrued Unbilled Revenues	28,373	46,281
Miscellaneous	3,343	3,400
Allowance for Uncollectible Accounts	(8,779)	(4,334)
Total Accounts Receivable	275,834	323,774
Fuel	89,129	77,077
Materials and Supplies	71,994	56,235
Risk Management Assets	84,562	105,376
Accrued Tax Benefits	10,095	3,748
Regulatory Asset for Under-Recovered Fuel Costs	6,591	29,526
Prepayments and Other	17,266	20,126
TOTAL	556,823	618,180
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,487,306	2,844,803
Transmission	1,658,340	1,620,512
Distribution	2,309,637	2,237,887
Other	344,201	339,450
Construction Work in Progress	592,554	957,626
Total	8,392,038	8,000,278
Accumulated Depreciation and Amortization	2,554,296	2,476,290
TOTAL - NET	5,837,742	5,523,988
OTHER NONCURRENT ASSETS		
Regulatory Assets	675,027	622,153
Long-term Risk Management Assets	86,948	88,906
Deferred Charges and Other	163,892	163,089
TOTAL	925,867	874,148
TOTAL ASSETS	$ 7,320,432	$ 7,016,316

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 247,616	$ 34,975
Accounts Payable:		
General	232,509	296,437
Affiliated Companies	92,697	105,525
Long-term Debt Due Within One Year – Nonaffiliated	399,144	324,191
Risk Management Liabilities	59,720	81,114
Customer Deposits	64,285	56,364
Accrued Taxes	102,445	60,056
Other	260,549	172,943
TOTAL	1,458,965	1,131,605
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,050,742	2,174,473
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	58,768	64,909
Deferred Income Taxes	892,735	957,229
Regulatory Liabilities and Deferred Investment Tax Credits	487,643	309,724
Deferred Credits and Other	235,127	224,439
TOTAL	3,825,015	3,830,774
TOTAL LIABILITIES	5,283,980	4,962,379
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,763	17,763
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,025,070	1,024,994
Retained Earnings	772,097	805,513
Accumulated Other Comprehensive Income (Loss)	(38,936)	(54,791)
TOTAL	2,018,689	2,036,174
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,320,432	$ 7,016,316

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
OPERATING ACTIVITIES		
Net Income (Loss)	$ (5,255)	$ 83,241
Adjustments for Noncash Items:		
Depreciation and Amortization	90,236	96,956
Deferred Income Taxes	(17,439)	(1,466)
Extraordinary Loss, Net of Tax	78,763	-
Regulatory Provision	105,110	-
Carrying Costs Income	(14,116)	(13,784)
Mark-to-Market of Risk Management Contracts	1,377	147
Change in Other Noncurrent Assets	(12,254)	5,690
Change in Other Noncurrent Liabilities	(1,239)	17,986
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	31,483	60,345
Fuel, Materials and Supplies	(20,654)	(8,611)
Margin Deposits	6,798	27,872
Accounts Payable	(26,786)	14,993
Customer Deposits	7,921	(24,824)
Accrued Taxes, Net	39,168	42,357
Fuel Over/Under Recovery, Net	15,221	3,636
Other Current Assets	(1,833)	7,295
Other Current Liabilities	(11,087)	5,137
Net Cash Flows From Operating Activities	265,414	316,970
INVESTING ACTIVITIES		
Construction Expenditures	(382,501)	(404,252)
Change in Other Cash Deposits, Net	(2,678)	-
Change in Advances to Affiliates, Net	-	(218,702)
Proceeds from Sales of Assets	6,194	4,034
Net Cash Flows Used For Investing Activities	(378,985)	(618,920)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	73,438	544,364
Change in Advances from Affiliates, Net	212,641	(194,133)
Retirement of Long-term Debt – Nonaffiliated	(125,006)	(100,005)
Retirement of Preferred Stock	-	(14)
Principal Payments for Capital Lease Obligations	(2,200)	(2,768)
Funds From Amended Coal Contract	-	68,078
Amortization of Funds From Amended Coal Contract	(20,868)	(8,567)
Dividends Paid on Common Stock	(25,000)	(5,000)
Dividends Paid on Cumulative Preferred Stock	(400)	(400)
Net Cash Flows From Financing Activities	112,605	301,555
Net Decrease in Cash and Cash Equivalents	(966)	(395)
Cash and Cash Equivalents at Beginning of Period	2,318	1,741

Cash and Cash Equivalents at End of Period	$	1,352	$	1,346
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	69,823	$	51,558
Net Cash Paid for Income Taxes		6,197		4,562
Noncash Acquisitions Under Capital Leases		1,693		2,287
Construction Expenditures Included in Accounts Payable at June 30,		97,044		105,826

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

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

Results of Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

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

Second Quarter of 2006		$ 32
Changes in Gross Margin:		
Retail Margins	64	
Off-system Sales	10	
Transmission Revenues	3	
Other	1	
Total Change in Gross Margin		78
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(8)	
Depreciation and Amortization	(3)	
Taxes Other Than Income Taxes	6	
Interest Expense	1	
Total Change in Operating Expenses and Other		(4)
Income Tax Expense		(26)
Second Quarter of 2007		$ 80

Net Income increased $48 million to $80 million in 2007. The key driver of the increase was a $78 million increase in Gross Margin primarily offset by a $26 million increase in Income Tax Expense.

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

- Retail Margins increased $64 million primarily due to:
  - A $22 million increase in rate revenues related to a $13 million increase in CSPCo's RSP, a $3 million increase related to recovery of storm costs and a $3 million increase related to recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The increase in recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs

was offset by the amortization of deferred expenses in Depreciation and Amortization.

- A $20 million decrease in capacity purchases due to changes in relative peak demands of AEP Power Pool members under the Interconnection Agreement.
- An $18 million increase in residential and commercial revenue primarily due to a 69% increase in cooling degree days.
- A $14 million increase in industrial revenue primarily due to the addition of Ormet, a major industrial customer. The addition of Ormet resulted in a $12 million increase in industrial sales. See "Ormet" section of Note 3.

- Margins from Off-system Sales increased $10 million primarily due to higher power prices in the east and higher trading margins.
- Transmission Revenues increased $3 million primarily due to a provision recorded in the second quarter of 2006 related to potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $8 million primarily due to:
  - A $4 million increase in expenses related to CSPCo's PPA for AEGCo's Lawrenceburg Plant which began in May 2007.
  - A $3 million increase in overhead line expenses due in part to the amortization of deferred storm expenses recovered through a cost-recovery rider. The increase in amortization of deferred storm expenses was offset by a corresponding increase in Retail Margins.
  - A $3 million increase in net allocated transmission costs related to the Transmission Equalization Agreement as a result of the addition of APCo's Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.
- Depreciation and Amortization increased $3 million due to the amortization of IGCC preconstruction costs in 2007. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Taxes Other Than Income Taxes decreased $6 million due to a favorable true-up of property taxes recorded in 2007 compared to an unfavorable true-up recorded in 2006, partially offset by an increase in state excise taxes.

Income Taxes

Income Tax Expense increased $26 million primarily due to an increase in pretax book income.

<u>Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006</u>

Reconciliation of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2007
Net Income
(in millions)

Six Months Ended June 30, 2006		$ 84
Changes in Gross Margin:		
Retail Margins	91	
Off-system Sales	(1)	
Transmission Revenues	(4)	
Other	(3)	
Total Change in Gross Margin		83

Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(18)	
Depreciation and Amortization	(7)	
Taxes Other Than Income Taxes	5	
Interest Expense	3	
Total Change in Operating Expenses and Other		(17)
Income Tax Expense		(23)
Six Months Ended June 30, 2007		$ 127

Net Income increased $43 million to $127 million in 2007. The key driver of the increase was an $83 million increase in Gross Margin partially offset by a $23 million increase in Income Tax Expense and a $17 million increase in Operating Expenses and Other.

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

- Retail Margins increased $91 million primarily due to:
  - A $36 million increase in rate revenues related to a $18 million increase in CSPCo's RSP, a $6 million increase related to recovery of storm costs and a $6 million increase related to recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs was offset by the amortization of deferred expenses in Depreciation and Amortization.
  - A $28 million increase in residential and commercial revenue primarily due to a 72% increase in cooling degree days.
  - A $21 million increase in industrial revenue primarily due to the addition of Ormet, a major industrial customer. The addition of Ormet resulted in a $19 million increase in industrial sales. See "Ormet" section of Note 3.
  - An $18 million decrease in capacity purchases due to changes in relative peak demands of AEP Power Pool members under the Interconnection Agreement.
- Transmission Revenues decreased $4 million primarily due to the elimination of SECA revenues as of April 1, 2006 offset by a provision recorded in the second quarter of 2006 related to potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.
- Other revenues decreased $3 million primarily due to lower gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $18 million primarily due to:
  - An $8 million increase in overhead line expenses primarily due to a $6 million increase in amortization of deferred storm expenses recovered through a cost-recovery rider. The increase in amortization of deferred storm expenses was offset by a corresponding increase in Retail Margins.
  - A $6 million increase in net allocated transmission costs related to the Transmission Equalization Agreement as a result of the addition of APCo's Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.
  -

A $4 million increase in expenses related to CSPCo's PPA for AEGCo's Lawrenceburg Plant which began in May 2007.

- Depreciation and Amortization increased $7 million primarily due to the amortization of IGCC preconstruction costs of $6 million in 2007. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Taxes Other Than Income Taxes decreased $5 million due to a favorable true-up of property taxes recorded in 2007 compared to an unfavorable true-up recorded in 2006, partially offset by an increase in state excise taxes.
- Interest Expense decreased $3 million primarily due to an increase in allowance for borrowed funds used during construction.

Income Taxes

Income Tax Expense increased $23 million primarily due to an increase in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

Management utilizes a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to exposure to interest rates primarily related to long-term debt with fixed interest rates was $82 million and $70 million at June 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

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

	Three Months Ended		Six Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Electric Generation, Transmission and Distribution	$ 469,648	$ 394,110	$ 893,114	$ 807,779
Sales to AEP Affiliates	35,356	21,762	58,369	35,531
Other	1,018	1,237	2,451	2,567
TOTAL	506,022	417,109	953,934	845,877
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	76,342	71,213	152,204	141,033
Purchased Electricity for Resale	32,835	27,688	64,146	52,453
Purchased Electricity from AEP Affiliates	87,788	87,188	171,329	169,665
Other Operation	62,516	57,860	123,675	113,805
Maintenance	26,723	23,502	49,287	41,436
Depreciation and Amortization	49,446	46,540	99,743	92,368
Taxes Other Than Income Taxes	35,796	41,787	76,378	81,289
TOTAL	371,446	355,778	736,762	692,049
OPERATING INCOME	134,576	61,331	217,172	153,828
Other Income (Expense):				
Interest Income	194	475	616	930
Carrying Costs Income	1,139	1,320	2,231	2,036
Allowance for Equity Funds Used During Construction	620	343	1,392	807
Interest Expense	(16,382)	(16,914)	(31,663)	(34,434)
INCOME BEFORE INCOME TAXES	120,147	46,555	189,748	123,167
Income Tax Expense	40,125	14,293	62,745	39,568
NET INCOME	80,022	32,262	127,003	83,599
Capital Stock Expense	40	40	79	79
EARNINGS APPLICABLE TO COMMON STOCK	$ 79,982	$ 32,222	$ 126,924	$ 83,520

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 41,026	$ 580,035	$ 361,365	$ (880)	$ 981,546
Common Stock Dividends			(45,000)		(45,000)
Capital Stock Expense		79	(79)		-
TOTAL					936,546
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $3,695				6,861	6,861
NET INCOME			83,599		83,599
TOTAL COMPREHENSIVE INCOME					90,460
JUNE 30, 2006	$ 41,026	$ 580,114	$ 399,885	$ 5,981	$ 1,027,006
DECEMBER 31, 2006	$ 41,026	$ 580,192	$ 456,787	$ (21,988)	$ 1,056,017
FIN 48 Adoption, Net of Tax			(3,022)		(3,022)
Common Stock Dividends			(40,000)		(40,000)
Capital Stock Expense		79	(79)		-
TOTAL					1,012,995
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $360				669	669
NET INCOME			127,003		127,003
TOTAL COMPREHENSIVE INCOME					127,672
JUNE 30, 2007	$ 41,026	$ 580,271	$ 540,689	$ (21,319)	$ 1,140,667

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,065	$ 1,319
Accounts Receivable:		
Customers	51,013	49,362
Affiliated Companies	35,509	62,866
Accrued Unbilled Revenues	18,760	11,042
Miscellaneous	6,266	4,895
Allowance for Uncollectible Accounts	(707)	(546)
Total Accounts Receivable	110,841	127,619
Fuel	41,922	37,348
Materials and Supplies	36,267	31,765
Emission Allowances	6,328	3,493
Risk Management Assets	45,433	66,238
Prepayments and Other	10,397	20,870
TOTAL	252,253	288,652
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,051,385	1,896,073
Transmission	491,245	479,119
Distribution	1,514,251	1,475,758
Other	202,545	191,103
Construction Work in Progress	322,114	294,138
Total	4,581,540	4,336,191
Accumulated Depreciation and Amortization	1,647,537	1,611,043
TOTAL - NET	2,934,003	2,725,148
OTHER NONCURRENT ASSETS		
Regulatory Assets	271,205	298,304
Long-term Risk Management Assets	46,558	56,206
Deferred Charges and Other	114,735	152,379
TOTAL	432,498	506,889
TOTAL ASSETS	$ 3,618,754	$ 3,520,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 64,003	$ 696
Accounts Payable:		
General	104,586	112,431
Affiliated Companies	42,580	59,538
Long-term Debt Due Within One Year - Nonaffiliated	112,000	-
Risk Management Liabilities	32,018	49,285
Customer Deposits	50,686	34,991
Accrued Taxes	158,915	166,551
Accrued Interest	23,155	20,868
Other	38,262	37,143
TOTAL	626,205	481,503
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	985,523	1,097,322
Long-term Debt – Affiliated	100,000	100,000
Long-term Risk Management Liabilities	31,956	40,477
Deferred Income Taxes	461,738	475,888
Regulatory Liabilities and Deferred Investment Tax Credits	169,757	179,048
Deferred Credits and Other	102,908	90,434
TOTAL	1,851,882	1,983,169
TOTAL LIABILITIES	2,478,087	2,464,672
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,271	580,192
Retained Earnings	540,689	456,787
Accumulated Other Comprehensive Income (Loss)	(21,319)	(21,988)
TOTAL	1,140,667	1,056,017
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 3,618,754	$ 3,520,689

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 127,003	$ 83,599
Adjustments for Noncash Items:		
Depreciation and Amortization	99,743	92,368
Deferred Income Taxes	(5,077)	(250)
Carrying Costs Income	(2,231)	(2,036)
Mark-to-Market of Risk Management Contracts	5,600	(466)
Deferred Property Taxes	39,063	30,201
Change in Other Noncurrent Assets	(25,985)	(15,417)
Change in Other Noncurrent Liabilities	(7,054)	7,111
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	7,678	29,274
Fuel, Materials and Supplies	(4,740)	(14,664)
Accounts Payable	(10,735)	16,866
Customer Deposits	15,695	(14,843)
Accrued Taxes, Net	5,493	(21,909)
Other Current Assets	5,608	24,796
Other Current Liabilities	(1,952)	(1,062)
Net Cash Flows From Operating Activities	248,109	213,568
INVESTING ACTIVITIES		
Construction Expenditures	(169,014)	(137,728)
Change in Advances to Affiliates, Net	-	(12,616)
Acquisition of Darby Plant	(102,032)	-
Proceeds from Sale of Assets	842	1,976
Other	(20)	(1,151)
Net Cash Flows Used For Investing Activities	(270,224)	(149,519)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	63,307	(17,609)
Principal Payments for Capital Lease Obligations	(1,446)	(1,570)
Dividends Paid on Common Stock	(40,000)	(45,000)
Net Cash Flows From (Used For) Financing Activities	21,861	(64,179)
Net Decrease in Cash and Cash Equivalents	(254)	(130)
Cash and Cash Equivalents at Beginning of Period	1,319	940
Cash and Cash Equivalents at End of Period	$ 1,065	$ 810
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 31,557	$ 32,374
Net Cash Paid for Income Taxes	1,704	10,713
Noncash Acquisitions Under Capital Leases	1,347	1,648
Construction Expenditures Included in Accounts Payable at June 30,	30,659	12,601
Noncash Assumption of Liabilities Related to Acquisition of Darby Plant	2,339	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

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

Second Quarter of 2006		$ 29
Changes in Gross Margin:		
Retail Margins	(7)	
FERC Municipals and Cooperatives	16	
Off-system Sales	6	
Transmission Revenues	6	
Other	2	
Total Change in Gross Margin		23
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(13)	
Depreciation and Amortization	(3)	
Other Income	(1)	
Interest Expense	(2)	
Total Change in Operating Expenses and Other		(19)
Income Tax Expense		(3)
Second Quarter of 2007		$ 30

Net Income increased $1 million to $30 million in 2007. The key drivers of the increase were a $23 million increase in Gross Margin offset by a $19 million increase in Operating Expenses and Other and a $3 million increase in Income Tax Expense.

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

- Retail Margins decreased $7 million primarily due to a $12 million reduction in capacity settlement revenues under the Interconnection Agreement reflecting I&M's new peak demand in July 2006 and lower revenues from financial transmission rights, net of congestion, of $7 million due to fewer constraints in the PJM market. Higher retail sales of $14 million reflecting favorable weather conditions partially offset the decreases. Heating and cooling degree days increased significantly in both the Indiana and Michigan jurisdictions.
- FERC Municipals and Cooperatives margins increased $16 million due to the addition of new municipal contracts including new rates and increased demand effective July 2006 and January 2007.
- Margins from Off-system Sales increased $6 million primarily due to higher power prices in the east and higher trading margins.
-

Transmission Revenues increased $6 million primarily due to a provision recorded in the second quarter of 2006 for potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $13 million primarily due to a $7 million increase in coal-fired steam plant maintenance expenses resulting from a planned outage at the Rockport Plant and a $4 million increase in transmission expense due to reduced credits under the Transmission Equalization Agreement. Credits decreased due to I&M's July 2006 peak and due to APCo's addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006 thus decreasing I&M's share of the transmission investment pool.
- Depreciation and Amortization expense increased $3 million primarily due to a $2 million increase in amortization related to capitalized software development costs and a $1 million increase in depreciation related to capital additions.
- Interest Expense increased $2 million primarily due to an increase in outstanding long-term debt and higher interest rates.

Income Taxes

Income Tax Expense increased $3 million primarily due to an increase in pretax book income and state income taxes.

<u>Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006</u>

Reconciliation of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2007
Net Income
(in millions)

Six Months Ended June 30, 2006		$ 86
Changes in Gross Margin:		
Retail Margins	(30)	
FERC Municipals and Cooperatives	25	
Off-system Sales	2	
Transmission Revenues	4	
Other	(5)	
Total Change in Gross Margin		(4)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(20)	
Depreciation and Amortization	(10)	
Taxes Other Than Income Taxes	1	
Other Income	(2)	
Interest Expense	(4)	
Total Change in Operating Expenses and Other		(35)
Income Tax Expense		12
Six Months Ended June 30, 2007		$ 59

Net Income decreased $27 million to $59 million in 2007. The key drivers of the decrease were a $4 million decrease in Gross Margin and a $35 million increase in Operating Expenses and Other partially offset by a $12 million decrease in Income Tax Expense.

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

- Retail Margins decreased $30 million primarily due to a $35 million reduction in capacity settlement revenues under the Interconnection Agreement reflecting I&M's new peak demand in July 2006 and lower revenues from financial transmission rights, net of congestion, of $16 million due to fewer constraints in the PJM market. Higher retail sales of $27 million reflecting favorable weather conditions partially offset the decreases. Heating and cooling degree days increased significantly in both the Indiana and Michigan jurisdictions.
- FERC Municipals and Cooperatives margins increased $25 million due to the addition of new municipal contracts including new rates and increased demand effective July 2006 and January 2007.
- Transmission Revenues increased $4 million primarily due to a provision recorded in the second quarter of 2006 for potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.
- Other revenues decreased $5 million primarily due to decreased River Transportation Division (RTD) revenues for barging coal and decreased gains on sales of emission allowances. RTD related expenses which offset the RTD revenue decrease are included in Other Operation on the Condensed Consolidated Statements of Income resulting in earning only a return approved under regulatory order.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $20 million primarily due to a $10 million increase in coal-fired plant maintenance expenses resulting from planned outages at Rockport and Tanners Creek plants and a $10 million increase in transmission expense due to reduced credits under the Transmission Equalization Agreement. Credits decreased due to I&M's July 2006 peak and due to APCo's addition of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006 thus decreasing I&M's share of the transmission investment pool.
- Depreciation and Amortization expense increased $10 million primarily due to a $6 million increase in depreciation related to capital additions and a $4 million increase in amortization related to capitalized software development costs.
- Interest Expense increased $4 million primarily due to an increase in outstanding long-term debt and higher interest rates.

Income Taxes

Income Tax Expense decreased $12 million primarily due to a decrease in pretax book income.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

Management utilizes a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to exposure to interest rates primarily related to long-term debt with fixed interest rates was $115 million and $93 million at June 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

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

	Three Months Ended		Six Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Electric Generation, Transmission and Distribution	$ 402,152	$ 371,581	$ 807,316	$ 775,350
Sales to AEP Affiliates	62,962	80,401	130,391	168,935
Other – Affiliated	14,571	9,841	27,238	24,935
Other – Nonaffiliated	6,352	7,631	13,961	16,013
TOTAL	486,037	469,454	978,906	985,233
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	90,650	96,147	186,767	185,599
Purchased Electricity for Resale	19,310	15,533	37,250	26,543
Purchased Electricity from AEP Affiliates	75,791	80,830	153,304	167,252
Other Operation	117,311	109,388	238,044	221,005
Maintenance	45,725	40,352	88,155	85,571
Depreciation and Amortization	53,890	50,778	110,197	100,493
Taxes Other Than Income Taxes	19,238	18,965	37,232	37,871
TOTAL	421,915	411,993	850,949	824,334
OPERATING INCOME	64,122	57,461	127,957	160,899
Other Income (Expense):				
Interest Income	707	663	1,295	1,357
Allowance for Equity Funds Used During Construction	727	1,440	992	3,364
Interest Expense	(19,611)	(17,902)	(39,432)	(35,435)
INCOME BEFORE INCOME TAXES	45,945	41,662	90,812	130,185
Income Tax Expense	15,910	13,137	31,314	43,782
NET INCOME	30,035	28,525	59,498	86,403
Preferred Stock Dividend Requirements	85	85	170	170
EARNINGS APPLICABLE TO COMMON STOCK	$ 29,950	$ 28,440	$ 59,328	$ 86,233

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 56,584	$ 861,290	$ 305,787	$ (3,569)	$ 1,220,092
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(170)		(170)
TOTAL					1,199,922
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,685				8,701	8,701
NET INCOME			86,403		86,403
TOTAL COMPREHENSIVE INCOME					95,104
JUNE 30, 2006	$ 56,584	$ 861,290	$ 372,020	$ 5,132	$ 1,295,026
DECEMBER 31, 2006	$ 56,584	$ 861,290	$ 386,616	$ (15,051)	$ 1,289,439
FIN 48 Adoption, Net of Tax			327		327
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(170)		(170)
Gain on Reacquired Preferred Stock		1			1
TOTAL					1,269,597
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $649				1,206	1,206
NET INCOME			59,498		59,498
TOTAL COMPREHENSIVE INCOME					60,704
JUNE 30, 2007	$ 56,584	$ 861,291	$ 426,271	$ (13,845)	$ 1,330,301

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 607	$ 1,369
Accounts Receivable:		
Customers	74,465	82,102
Affiliated Companies	68,135	108,288
Accrued Unbilled Revenues	3,947	2,206
Miscellaneous	1,648	1,838
Allowance for Uncollectible Accounts	(729)	(601)
Total Accounts Receivable	147,466	193,833
Fuel	51,416	64,669
Materials and Supplies	137,849	129,953
Risk Management Assets	47,684	69,752
Accrued Tax Benefits	-	27,378
Prepayments and Other	9,740	15,170
TOTAL	394,762	502,124
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,402,290	3,363,813
Transmission	1,062,935	1,047,264
Distribution	1,159,964	1,102,033
Other (including nuclear fuel and coal mining)	556,848	529,727
Construction Work in Progress	150,684	183,893
Total	6,332,721	6,226,730
Accumulated Depreciation, Depletion and Amortization	2,970,351	2,914,131
TOTAL - NET	3,362,370	3,312,599
OTHER NONCURRENT ASSETS		
Regulatory Assets	274,468	314,805
Spent Nuclear Fuel and Decommissioning Trusts	1,310,871	1,248,319
Long-term Risk Management Assets	48,908	59,137
Deferred Charges and Other	108,343	109,453
TOTAL	1,742,590	1,731,714
TOTAL ASSETS	$ 5,499,722	$ 5,546,437

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 14,941	$ 91,173
Accounts Payable:		
General	120,551	146,733
Affiliated Companies	53,583	65,497
Long-term Debt Due Within One Year – Nonaffiliated	-	50,000
Risk Management Liabilities	33,508	52,083
Customer Deposits	36,490	34,946
Accrued Taxes	100,860	59,652
Other	113,497	128,461
TOTAL	473,430	628,545
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,561,600	1,505,135
Long-term Risk Management Liabilities	33,545	42,641
Deferred Income Taxes	305,148	335,000
Regulatory Liabilities and Deferred Investment Tax Credits	784,082	753,402
Asset Retirement Obligations	831,051	809,853
Deferred Credits and Other	172,485	174,340
TOTAL	3,687,911	3,620,371
TOTAL LIABILITIES	4,161,341	4,248,916
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,080	8,082
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	861,291	861,290
Retained Earnings	426,271	386,616
Accumulated Other Comprehensive Income (Loss)	(13,845)	(15,051)
TOTAL	1,330,301	1,289,439
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,499,722	$ 5,546,437

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 59,498	$ 86,403
Adjustments for Noncash Items:		
Depreciation and Amortization	110,197	100,493
Deferred Income Taxes	(9,547)	9,562
Deferred Investment Tax Credits	(3,471)	(3,640)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	23,099	(12,111)
Amortization of Nuclear Fuel	33,003	24,928
Mark-to-Market of Risk Management Contracts	5,607	(634)
Change in Other Noncurrent Assets	(12,308)	7,630
Change in Other Noncurrent Liabilities	22,896	14,701
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	36,805	56,894
Fuel, Materials and Supplies	9,911	(12,092)
Accounts Payable	(46,049)	4,221
Customer Deposits	1,544	(14,867)
Accrued Taxes, Net	72,977	28,256
Other Current Assets	4,595	21,921
Other Current Liabilities	(17,858)	(21,559)
Net Cash Flows From Operating Activities	290,899	290,106
INVESTING ACTIVITIES		
Construction Expenditures	(124,252)	(169,491)
Purchases of Investment Securities	(409,163)	(434,212)
Sales of Investment Securities	370,986	405,716
Acquisitions of Nuclear Fuel	(30,498)	(35,195)
Other	292	2,273
Net Cash Flows Used For Investing Activities	(192,635)	(230,909)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	49,745
Change in Advances from Affiliates, Net	(76,232)	(35,953)
Retirement of Long-term Debt – Nonaffiliated	-	(50,000)
Retirement of Cumulative Preferred Stock	(2)	-
Principal Payments for Capital Lease Obligations	(2,622)	(3,139)
Dividends Paid on Common Stock	(20,000)	(20,000)
Dividends Paid on Cumulative Preferred Stock	(170)	(170)
Net Cash Flows Used For Financing Activities	(99,026)	(59,517)
Net Decrease in Cash and Cash Equivalents	(762)	(320)
Cash and Cash Equivalents at Beginning of Period	1,369	854
Cash and Cash Equivalents at End of Period	$ 607	$ 534
SUPPLEMENTARY INFORMATION		

Cash Paid for Interest, Net of Capitalized Amounts	$ 32,082	$ 32,959
Net Cash Paid (Received) for Income Taxes	(20,001)	12,031
Noncash Acquisitions Under Capital Leases	1,160	3,185
Construction Expenditures Included in Accounts Payable at June 30,	24,145	18,031
Acquisition of Nuclear Fuel in Accounts Payable at June 30,	30,867	25,780

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

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

Second Quarter of 2006		$ 23
Changes in Gross Margin:		
Retail Margins	59	
Off-system Sales	4	
Transmission Revenues	4	
Other	(4)	
Total Change in Gross Margin		63
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	33	
Depreciation and Amortization	(7)	
Taxes Other Than Income Taxes	(2)	
Interest Expense	(9)	
Total Change in Operating Expenses and Other		15
Income Tax Expense		(27)
Second Quarter of 2007		$ 74

Net Income increased $51 million to $74 million in 2007. The key drivers of the increase were a $63 million increase in Gross Margin and a $15 million decrease in Operating Expenses and Other offset by a $27 million increase in Income Tax Expense.

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

- Retail Margins increased $59 million primarily due to the following:
  - A $16 million increase in capacity settlements under the Interconnection Agreement related to certain affiliates' peaks and the June 2006 expiration of OPCo's supplemental capacity and energy obligation to Buckeye Power, Inc. under the Cardinal Station Agreement.
  - A $14 million increase in industrial revenue primarily due to the addition of Ormet, a major industrial customer. The addition of Ormet resulted in a $12 million increase in industrial sales. See "Ormet" section of Note 3.
  - A $13 million increase in rate revenues primarily related to an $11 million increase in OPCo's RSP, a $3 million increase related to rate recovery of storm costs and a $3 million increase related to rate recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The increase in rate recovery of storm costs was offset by the amortization of

deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs was offset by the amortization of deferred expenses in Depreciation and Amortization.
- A $13 million increase in residential and commercial revenue primarily due to a 71% increase in cooling degree days.
- A $12 million increase in fuel margins.

- Margins from Off-system Sales increased $4 million primarily due to a $15 million increase in trading margins as the result of higher power prices in the east offset by an $8 million decrease related to OPCo's purchase power and sale agreement with Dow Chemical Company (Dow) which ended in November 2006 and a $3 million decrease in OPCo's allocated share of off-system sales revenue due to an affiliate's new peak. Margins related to Dow were offset by a corresponding decrease in Other Operation and Maintenance expenses. See "OPCo Indemnification Agreement with AEP Resources" section of Note 16 in the 2006 Annual Report for further discussion related to Dow.
- Transmission Revenues increased $4 million primarily due to a provision recorded in the second quarter of 2006 related to potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.
- Other revenues decreased $4 million primarily due to a $3 million decrease related to the April 2006 expiration of an obligation to sell supplemental capacity and energy to Buckeye Power, Inc. under the Cardinal Station Agreement and a $1 million decrease in gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $33 million primarily due to:
  - An $18 million decrease in maintenance from planned and forced outages at the Gavin, Muskingum River, Kammer and Sporn Plants related to boiler tube inspections in 2006.
  - An $8 million decrease due to the absence of maintenance and rental expenses related to OPCo's purchase power and sale agreement with Dow which ended in November 2006. The decrease in Other Operation and Maintenance expenses related to Dow were offset by a corresponding decrease in margins from Off-system Sales.
  - A $5 million decrease in removal costs at the Mitchell, Sporn and Amos Plants related to outages in 2006.

  These amounts were offset by:
  - A $3 million increase in overhead line expenses due in part to the amortization of deferred storm expenses recovered through a cost-recovery rider. The increase was offset by a corresponding increase in Retail Margins.
- Depreciation and Amortization increased $7 million primarily due to a $6 million increase in depreciation related to environmental improvements placed in service at the Mitchell Plant and the amortization of IGCC preconstruction costs of $3 million. These increases were offset by a $2 million decrease in amortization of a regulatory liability related to Ormet. See "Ormet" section of Note 3. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Interest Expense increased $9 million due to long-term debt issuances since May 2006.

Income Taxes

Income Tax Expense increased $27 million primarily due to an increase in pretax book income.

<u>Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006</u>

Reconciliation of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2007

Net Income
(in millions)

Six Months Ended June 30, 2006		$ 118
Changes in Gross Margin:		
Retail Margins	118	
Off-system Sales	(17)	
Transmission Revenues	(6)	
Other	(14)	
Total Change in Gross Margin		81
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	5	
Depreciation and Amortization	(12)	
Taxes Other Than Income Taxes	(3)	
Interest Expense	(12)	
Total Change in Operating Expenses and Other		(22)
Income Tax Expense		(23)
Six Months Ended June 30, 2007		$ 154

Net Income increased $36 million to $154 million in 2007. The key driver of the increase was an $81 million increase in Gross Margin offset by a $23 million increase in Income Tax Expense and a $22 million increase in Operating Expenses and Other.

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

- Retail Margins increased $118 million primarily due to the following:
  - A $41 million increase in capacity settlements under the Interconnection Agreement related to certain affiliates' peaks and the June 2006 expiration of OPCo's supplemental capacity and energy obligation to Buckeye Power, Inc. under the Cardinal Station Agreement.
  - A $35 million increase in rate revenues primarily related to a $20 million increase in OPCo's RSP, a $6 million increase related to rate recovery of storm costs and a $6 million increase related to rate recovery of IGCC preconstruction costs. See "Ohio Rate Matters" section of Note 3. The increase in rate recovery of storm costs was offset by the amortization of deferred expenses in Other Operation and Maintenance. The increase in rate recovery of IGCC preconstruction costs was offset by the amortization of deferred expenses in Depreciation and Amortization.
  - A $20 million increase in residential and commercial revenue primarily due to a 73% increase in cooling degree days.
  - An $18 million increase in industrial revenue due to the addition of Ormet, a major industrial customer. See "Ormet" section of Note 3.

  These increases were partially offset by:
  - An $8 million decrease in revenues associated with SO_2 allowances received in 2006 from Buckeye Power, Inc. under the Cardinal Station Allowances Agreement.

- Margins from Off-system Sales decreased $17 million primarily due to a $20 million decrease in OPCo's allocated share of off-system sales revenues due to an affiliate's new peak and a $9 million decrease in margins related to OPCo's purchase power and sale agreement with Dow which ended in November 2006. These decreases were offset by higher trading margins of $11 million as the result of higher power prices in the east and a change in the allocation of off-system sales margins under the SIA effective April 1, 2006. Margins related to Dow were offset by a corresponding decrease in Other Operation and Maintenance expenses.
- Transmission Revenues decreased $6 million primarily due to the elimination of SECA revenues as of April 1, 2006 offset by a provision recorded in the second quarter of 2006 related to potential SECA refunds. See "Transmission Rate Proceedings at the FERC" section of Note 3.
- Other revenues decreased $14 million primarily due to a $7 million decrease related to the April 2006 expiration of an obligation to sell supplemental capacity and energy to Buckeye Power, Inc. under the Cardinal Station Agreement and a $4 million decrease in gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $5 million primarily due to the following:
    - A $16 million decrease in maintenance from planned and forced outages at the Muskingum River, Kammer and Sporn Plants related to boiler tube inspections in 2006.
    - A $9 million decrease in maintenance and rental expenses related to OPCo's purchase power and sale agreement with Dow which ended in November 2006. This decrease was offset by a corresponding decrease in margins from Off-system Sales.

  These decreases were partially offset by:
    - A $7 million increase in removal costs related to planned and forced outages at the Gavin, Mitchell and Cardinal Plants.
    - A $6 million increase in overhead line expenses due in part to the amortization of deferred storm expenses recovered through a cost-recovery rider. The increase was offset by a corresponding increase in Retail Margins.
    - A $5 million increase due to the February 2006 adjustment of liabilities related to sold coal companies.
- Depreciation and Amortization increased $12 million primarily due to a $9 million increase in depreciation related to environmental improvements placed in service at the Mitchell Plant and the amortization of IGCC preconstruction costs of $6 million in 2007. These increases were offset by a $3 million decrease in amortization of a regulatory liability related to Ormet. See "Ormet" section of Note 3. The increase in amortization of IGCC preconstruction costs was offset by a corresponding increase in Retail Margins.
- Interest Expense increased $12 million primarily due to a $15 million increase related to long-term debt issuances since May 2006 offset by a $5 million increase in allowance for borrowed funds used during construction.

Income Taxes

Income Tax Expense increased $23 million primarily due to an increase in pretax book income and state income taxes.

<u>Financial Condition</u>

Credit Ratings

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

Moody's	S&P	Fitch

Senior Unsecured Debt	A3	BBB	BBB+

Cash Flow

Cash flows for the six months ended June 30, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,625	$ 1,240
Cash Flows From (Used For):		
Operating Activities	279,029	321,944
Investing Activities	(560,262)	(512,468)
Financing Activities	282,607	190,274
Net Increase (Decrease) in Cash and Cash Equivalents	1,374	(250)
Cash and Cash Equivalents at End of Period	$ 2,999	$ 990

Operating Activities

Net Cash Flows From Operating Activities were $279 million in 2007. OPCo produced Net Income of $154 million during the period and a noncash expense item of $169 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 relates to a number of items. Accounts Payable had a $47 million cash outflow partially due to emission allowance payments in January 2007. Accrued Taxes, Net, had a $47 million cash inflow primarily due to an increase of federal income tax related accruals offset by temporary timing differences of payments for property taxes. Fuel, Materials and Supplies had a $42 million cash outflow primarily due to an increase in coal inventory in preparation for the summer cooling season and an increase in materials related to projects at the Mitchell, Amos, Gavin and Sporn Plants.

Net Cash Flows From Operating Activities were $322 million in 2006. OPCo produced Net Income of $118 million during the period and a noncash expense item of $157 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 prior period activity in working capital primarily relates to a number of items. Accounts Receivable, Net had a $98 million cash inflow primarily due to collected receivables from OPCo's affiliates related to power sales, settled litigation and emission allowances. Fuel, Materials and Supplies had a $56 million cash outflow primarily due to an increase in coal inventory in preparation for the summer cooling season. Accounts Payable had a $43 million cash outflow primarily due to timing differences for payments to affiliates related to the AEP Power Pool.

Investing Activities

Net Cash Flows Used For Investing Activities were $560 million and $512 million in 2007 and 2006, respectively. Construction Expenditures were $566 million and $482 million in 2007 and 2006, respectively, primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and the flue gas desulfurization projects at the Cardinal, Amos and Mitchell Plants. In January 2007, environmental upgrades were completed for Unit 2 at the Mitchell Plant. For the remainder of 2007, OPCo expects construction expenditures to be approximately $265 million.

Financing Activities

Net Cash Flows From Financing Activities were $283 million in 2007. OPCo issued Senior Unsecured Notes for $400 million and $65 million of Pollution Control Bonds. OPCo repaid borrowings of $165 million from the Utility Money Pool.

Net Cash Flows From Financing Activities were $190 million for 2006. OPCo issued Senior Unsecured Notes for $350 million and $65 million of Pollution Control Bonds. OPCo retired Notes Payable-Affiliated of $200 million. OPCo repaid borrowings of $70 million from the Utility Money Pool and received a Capital Contribution from Parent of $70 million.

Financing Activity

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

Issuances

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

Retirements

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

Liquidity

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

Summary Obligation Information

A summary of contractual obligations is included in the 2006 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" and "Financing Activity" above.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2006 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. Adverse results in these proceedings have the potential to materially affect results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on OPCo.

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	Cash Flow Hedges	DETM Assignment (a)	Total
Current Assets	$ 50,040	$ 7,267	$ -	$ 57,307
Noncurrent Assets	55,122	1,143	-	56,265
Total MTM Derivative Contract Assets	105,162	8,410	-	113,572
Current Liabilities	(40,629)	(174)	(2,315)	(43,118)
Noncurrent Liabilities	(34,290)	(56)	(4,898)	(39,244)
Total MTM Derivative Contract Liabilities	(74,919)	(230)	(7,213)	(82,362)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 30,243	$ 8,180	$ (7,213)	$ 31,210

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

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2007
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 33,042
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(5,664)
Fair Value of New Contracts at Inception When Entered During the Period (a)	311
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	332
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	2,670
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(448)
Total MTM Risk Management Contract Net Assets	30,243
Net Cash Flow Hedge Contracts	8,180
DETM Assignment (d)	(7,213)

Total MTM Risk Management Contract Net Assets at June 30, 2007	$	31,210

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

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

The following table presents:

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

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

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted –Exchange Traded Contracts	$ 3,646	$ (2,762)	$ 185	$ -	$ -	$ -	$ 1,069
Prices Provided by Other External Sources – OTC Broker Quotes (a)	3,153	10,662	8,581	3,706	-	-	26,102
Prices Based on Models and Other Valuation Methods (b)	(1,363)	(2,084)	1,078	3,562	810	1,069	3,072
Total	$ 5,436	$ 5,816	$ 9,844	$ 7,268	$ 810	$ 1,069	$ 30,243

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

of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available including values determinable by other third party transactions.

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

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

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

Management uses forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on the Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2006 to June 30, 2007. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2007
(in thousands)

	Power	Foreign Currency	Interest Rate	Total
Beginning Balance in AOCI December 31, 2006	$ 4,040	$ (331)	$ 3,553	$ 7,262
Changes in Fair Value	3,617	-	563	4,180
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(2,810)	7	(406)	(3,209)
Ending Balance in AOCI June 30, 2007	$ 4,847	$ (324)	$ 3,710	$ 8,233

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $5,504 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this

VaR analysis, at June 30, 2007, a near term typical change in commodity prices is not expected to have a material effect on results of operations, cash flows or financial condition.

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

Six Months Ended June 30, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$360	$2,054	$679	$195	$573	$1,451	$500	$271

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

VaR Associated with Debt Outstanding

Management utilizes a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to exposure to interest rates primarily related to long-term debt with fixed interest rates was $147 million and $110 million at June 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

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

	Three Months Ended		Six Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Electric Generation, Transmission and Distribution	$ 480,445	$ 453,064	$ 972,979	$ 997,703
Sales to AEP Affiliates	180,205	154,648	359,099	303,907
Other - Affiliated	6,817	3,866	10,855	7,575
Other - Nonaffiliated	3,466	4,429	7,441	9,428
TOTAL	670,933	616,007	1,350,374	1,318,613
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	201,338	211,538	399,631	446,668
Purchased Electricity for Resale	27,868	26,313	52,722	48,027
Purchased Electricity from AEP Affiliates	28,745	28,091	49,711	56,663
Other Operation	86,972	99,189	189,959	185,818
Maintenance	50,617	71,416	109,765	118,940
Depreciation and Amortization	84,779	77,855	169,055	156,676
Taxes Other Than Income Taxes	50,320	48,536	98,705	95,689
TOTAL	530,639	562,938	1,069,548	1,108,481
OPERATING INCOME	140,294	53,069	280,826	210,132
Other Income (Expense):				
Interest Income	472	595	884	1,232
Carrying Costs Income	3,594	3,451	7,135	6,834
Allowance for Equity Funds Used During Construction	446	398	1,017	1,136
Interest Expense	(33,734)	(24,437)	(59,665)	(47,851)
INCOME BEFORE INCOME TAXES	111,072	33,076	230,197	171,483
Income Tax Expense	36,732	9,677	76,596	53,052
NET INCOME	74,340	23,399	153,601	118,431
Preferred Stock Dividend Requirements	183	183	366	366
EARNINGS APPLICABLE TO COMMON STOCK	$ 74,157	$ 23,216	$ 153,235	$ 118,065

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 321,201	$ 466,637	$ 979,354	$ 755	$ 1,767,947
Capital Contribution From Parent		70,000			70,000
Preferred Stock Dividends			(366)		(366)
Gain on Reacquired Preferred Stock		2			2
TOTAL					1,837,583
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $5,708				10,600	10,600
NET INCOME			118,431		118,431
TOTAL COMPREHENSIVE INCOME					129,031
JUNE 30, 2006	$ 321,201	$ 536,639	$ 1,097,419	$ 11,355	$ 1,966,614
DECEMBER 31, 2006	$ 321,201	$ 536,639	$ 1,207,265	$ (56,763)	$ 2,008,342
FIN 48 Adoption, Net of Tax			(5,380)		(5,380)
Preferred Stock Dividends			(366)		(366)
TOTAL					2,002,596
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $523				971	971
NET INCOME			153,601		153,601
TOTAL COMPREHENSIVE INCOME					154,572
JUNE 30, 2007	$ 321,201	$ 536,639	$ 1,355,120	$ (55,792)	$ 2,157,168

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,999	$ 1,625
Accounts Receivable:		
Customers	89,097	86,116
Affiliated Companies	104,214	108,214
Accrued Unbilled Revenues	15,956	10,106
Miscellaneous	4,624	1,819
Allowance for Uncollectible Accounts	(1,004)	(824)
Total Accounts Receivable	212,887	205,431
Fuel	159,637	120,441
Materials and Supplies	85,650	74,840
Emission Allowances	8,817	10,388
Risk Management Assets	57,307	86,947
Accrued Tax Benefits	2,747	22,909
Prepayments and Other	16,524	18,416
TOTAL	546,568	540,997
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	5,492,398	4,413,340
Transmission	1,050,149	1,030,934
Distribution	1,355,421	1,322,103
Other	306,100	299,637
Construction Work in Progress	620,350	1,339,631
Total	8,824,418	8,405,645
Accumulated Depreciation and Amortization	2,871,803	2,836,584
TOTAL - NET	5,952,615	5,569,061
OTHER NONCURRENT ASSETS		
Regulatory Assets	366,748	414,180
Long-term Risk Management Assets	56,265	70,092
Deferred Charges and Other	201,227	224,403
TOTAL	624,240	708,675
TOTAL ASSETS	$ 7,123,423	$ 6,818,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 16,583	$ 181,281
Accounts Payable:		
General	167,508	250,025
Affiliated Companies	110,113	145,197
Short-term Debt – Nonaffiliated	-	1,203
Long-term Debt Due Within One Year – Nonaffiliated	16,390	17,854
Risk Management Liabilities	43,118	73,386
Customer Deposits	40,431	31,465
Accrued Taxes	187,851	165,338
Accrued Interest	44,612	35,497
Other	108,545	123,631
TOTAL	735,151	1,024,877
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,641,779	2,183,887
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	39,244	52,929
Deferred Income Taxes	893,989	911,221
Regulatory Liabilities and Deferred Investment Tax Credits	169,805	185,895
Deferred Credits and Other	252,350	219,127
TOTAL	4,197,167	3,753,059
TOTAL LIABILITIES	4,932,318	4,777,936
Minority Interest	17,310	15,825
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,627	16,630
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	536,639	536,639
Retained Earnings	1,355,120	1,207,265
Accumulated Other Comprehensive Income (Loss)	(55,792)	(56,763)
TOTAL	2,157,168	2,008,342
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,123,423	$ 6,818,733

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 153,601	$ 118,431
Adjustments for Noncash Items:		
Depreciation and Amortization	169,055	156,676
Deferred Income Taxes	550	(8,073)
Carrying Costs Income	(7,135)	(6,834)
Mark-to-Market of Risk Management Contracts	1,509	1,263
Deferred Property Taxes	34,629	35,550
Change in Other Noncurrent Assets	(18,338)	4,898
Change in Other Noncurrent Liabilities	272	16,355
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(18,273)	97,832
Fuel, Materials and Supplies	(42,452)	(56,075)
Accounts Payable	(46,758)	(42,878)
Accrued Taxes, Net	46,587	(7,233)
Other Current Assets	1,545	35,848
Other Current Liabilities	4,237	(23,816)
Net Cash Flows From Operating Activities	279,029	321,944
INVESTING ACTIVITIES		
Construction Expenditures	(565,832)	(481,541)
Change in Advances to Affiliates, Net	-	(36,787)
Proceeds from Sales of Assets	5,594	7,511
Other	(24)	(1,651)
Net Cash Flows Used For Investing Activities	(560,262)	(512,468)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	70,000
Issuance of Long-term Debt – Nonaffiliated	461,324	405,839
Change in Short-term Debt, Net – Nonaffiliated	(1,203)	(5,094)
Change in Advances from Affiliates, Net	(164,698)	(70,071)
Retirement of Long-term Debt – Nonaffiliated	(8,927)	(6,177)
Retirement of Long-term Debt – Affiliated	-	(200,000)
Retirement of Cumulative Preferred Stock	(2)	(8)
Principal Payments for Capital Lease Obligations	(3,521)	(3,849)
Dividends Paid on Cumulative Preferred Stock	(366)	(366)
Net Cash Flows From Financing Activities	282,607	190,274
Net Increase (Decrease) in Cash and Cash Equivalents	1,374	(250)
Cash and Cash Equivalents at Beginning of Period	1,625	1,240
Cash and Cash Equivalents at End of Period	$ 2,999	$ 990
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 51,991	$ 43,794

Net Cash Paid (Received) for Income Taxes	(9,193)	24,077
Noncash Acquisitions Under Capital Leases	1,036	1,662
Construction Expenditures Included in Accounts Payable at June 30,	65,936	97,389

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

Results of Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

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

Second Quarter of 2006		$	15
Changes in Gross Margin:			
Retail and Off-system Sales Margins	(2)		
Transmission Revenues	(1)		
Other	(2)		
Total Change in Gross Margin			(5)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(3)		
Depreciation and Amortization	(1)		
Interest Expense	(3)		
Total Change in Operating Expenses and Other			(7)
Income Tax Expense			3
Second Quarter of 2007		$	6

Net Income decreased $9 million to $6 million in 2007. The key drivers of the decreased income were a $5 million decrease in Gross Margin and a $7 million increase in Operating Expenses and Other, partially offset by a $3 million decrease in Income Tax Expense.

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

- Retail and Off-system Sales Margins decreased $2 million primarily due to a decrease in retail margins resulting from a 28% decrease in cooling days, partially offset by an increase in Off-system Sales Margins, 75% of which flows through the fuel adjustment clause to retail customers.
- Other revenues decreased $2 million primarily due to lower gains on sales of emission allowances and lower billings to outside parties for construction services.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased $3 million primarily due to an $8 million increase in generation operation and maintenance expense primarily during planned outages at PSO's Northeastern and Southwestern plants. This increase was partially offset by a $5 million decrease in distribution expenses, mostly due to a $7 million adjustment to capitalize costs related to a January 2007 ice storm.

· Interest Expense increased $3 million primarily due to increased borrowings.

Income Taxes

Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income, offset in part by state income taxes.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Reconciliation of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2007
Net Income (Loss)
(in millions)

Six Months Ended June 30, 2006		$ 9
Changes in Gross Margin:		
Retail and Off-system Sales Margins	2	
Transmission Revenues	1	
Other	(3)	
Total Change in Gross Margin		-
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(29)	
Depreciation and Amortization	(3)	
Interest Expense	(5)	
Total Change in Operating Expenses and Other		(37)
Income Tax Expense		14
Six Months Ended June 30, 2007		$ (14)

Net Income decreased $23 million to a $14 million loss in 2007. The key driver of the decreased income was a $37 million increase in Operating Expenses and Other, partially offset by a $14 million decrease in Income Tax Expense.

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

· Retail and Off-system Sales Margins increased $2 million primarily due to an increase in margins from Off-System Sales, 75% of which flows through the fuel adjustment clause to retail customers, partially offset by a decrease in retail margins resulting from a 25% decrease in cooling degree days.
· Other revenues decreased $3 million primarily due to lower billings to outside parties for construction services, as well as the absence of a 2006 settlement received from an electric cooperative.

Operating Expenses and Other increased between years as follows:

· Other Operation and Maintenance expenses increased $29 million primarily due to a $15 million increase in distribution maintenance expense primarily due to a January 2007 ice storm and a $10 million increase in generation operation and maintenance expense primarily

during planned outages at PSO’s Oklaunion, Riverside, Northeastern and Southwestern plants.
- Depreciation and Amortization increased $3 million due to higher depreciable asset balances.
- Interest Expense increased $5 million primarily due to increased borrowings.

Income Taxes

Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

VaR Associated with Debt Outstanding

Management utilizes a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to exposure to interest rates primarily related to long-term debt with fixed interest rates was $46 million and $39 million at June 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2007 and 2006
(in thousands)
(Unaudited)

	Three Months Ended 2007	Three Months Ended 2006	Six Months Ended 2007	Six Months Ended 2006
REVENUES				
Electric Generation, Transmission and Distribution	$ 304,820	$ 333,313	$ 594,900	$ 672,914
Sales to AEP Affiliates	16,275	12,545	40,868	26,613
Other	544	1,188	1,184	2,248
TOTAL	321,639	347,046	636,952	701,775
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	113,633	150,976	256,148	364,149
Purchased Electricity for Resale	70,145	56,358	137,554	89,575
Purchased Electricity from AEP Affiliates	18,979	15,880	32,463	37,111
Other Operation	42,345	39,985	83,352	76,741
Maintenance	22,177	22,033	65,262	42,340
Depreciation and Amortization	22,992	21,713	45,698	42,845
Taxes Other Than Income Taxes	9,890	10,077	20,184	20,153
TOTAL	300,161	317,022	640,661	672,914
OPERATING INCOME (LOSS)	21,478	30,024	(3,709)	28,861
Other Income	562	211	1,208	780
Interest Expense	(12,785)	(9,634)	(24,168)	(18,769)
INCOME (LOSS) BEFORE INCOME TAXES	9,255	20,601	(26,669)	10,872
Income Tax Expense (Credit)	2,960	5,963	(12,538)	1,591
NET INCOME (LOSS)	6,295	14,638	(14,131)	9,281
Preferred Stock Dividend Requirements	53	53	106	106
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 6,242	$ 14,585	$ (14,237)	$ 9,175

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 157,230	$ 230,016	$ 162,615	$ (1,264)	$ 548,597
Preferred Stock Dividends			(106)		(106)
TOTAL					548,491
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $375				696	696
NET INCOME			9,281		9,281
TOTAL COMPREHENSIVE INCOME					9,977
JUNE 30, 2006	$ 157,230	$ 230,016	$ 171,790	$ (568)	$ 558,468
DECEMBER 31, 2006	$ 157,230	$ 230,016	$ 199,262	$ (1,070)	$ 585,438
FIN 48 Adoption, Net of Tax			(386)		(386)
Capital Contribution from Parent		40,000			40,000
Preferred Stock Dividends			(106)		(106)
TOTAL					624,946
COMPREHENSIVE LOSS					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $49				91	91
NET LOSS			(14,131)		(14,131)
TOTAL COMPREHENSIVE LOSS					(14,040)
JUNE 30, 2007	$ 157,230	$ 270,016	$ 184,639	$ (979)	$ 610,906

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 908	$ 1,651
Accounts Receivable:		
Customers	52,773	70,319
Affiliated Companies	68,499	73,318
Miscellaneous	13,251	10,270
Allowance for Uncollectible Accounts	(34)	(5)
Total Accounts Receivable	134,489	153,902
Fuel	22,063	20,082
Materials and Supplies	54,818	48,375
Risk Management Assets	54,372	100,802
Accrued Tax Benefits	26,900	4,679
Regulatory Asset for Under-Recovered Fuel Costs	21,069	7,557
Margin Deposits	18,284	35,270
Prepayments and Other	17,849	5,732
TOTAL	350,752	378,050
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,109,356	1,091,910
Transmission	543,722	503,638
Distribution	1,284,347	1,215,236
Other	240,542	234,227
Construction Work in Progress	151,764	141,283
Total	3,329,731	3,186,294
Accumulated Depreciation and Amortization	1,203,048	1,187,107
TOTAL - NET	2,126,683	1,999,187
OTHER NONCURRENT ASSETS		
Regulatory Assets	153,154	142,905
Long-term Risk Management Assets	9,200	17,066
Employee Benefits and Pension Assets	29,362	30,161
Deferred Charges and Other	27,832	11,677
TOTAL	219,548	201,809
TOTAL ASSETS	$ 2,696,983	$ 2,579,046

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 216,239	$ 76,323
Accounts Payable:		
General	168,779	165,618
Affiliated Companies	80,116	65,134
Long-term Debt Due Within One Year – Nonaffiliated	12,660	-
Risk Management Liabilities	42,748	88,469
Customer Deposits	42,435	51,335
Accrued Taxes	34,327	19,984
Other	33,671	58,651
TOTAL	630,975	525,514
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	670,087	669,998
Long-term Risk Management Liabilities	6,481	11,448
Deferred Income Taxes	417,789	414,197
Regulatory Liabilities and Deferred Investment Tax Credits	295,381	315,584
Deferred Credits and Other	60,102	51,605
TOTAL	1,449,840	1,462,832
TOTAL LIABILITIES	2,080,815	1,988,346
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,262	5,262
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $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	270,016	230,016
Retained Earnings	184,639	199,262
Accumulated Other Comprehensive Income (Loss)	(979)	(1,070)
TOTAL	610,906	585,438
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,696,983	$ 2,579,046

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
OPERATING ACTIVITIES		
Net Income (Loss)	$ (14,131)	$ 9,281
Adjustments for Noncash Items:		
Depreciation and Amortization	45,698	42,845
Deferred Income Taxes	11,059	(22,319)
Mark-to-Market of Risk Management Contracts	3,608	(11,979)
Deferred Property Taxes	(16,539)	(16,196)
Change in Other Noncurrent Assets	(26,291)	9,441
Change in Other Noncurrent Liabilities	(22,811)	(8,232)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	19,413	8,080
Fuel, Materials and Supplies	(8,414)	(6,816)
Margin Deposits	16,986	(46,917)
Accounts Payable	11,810	28,517
Customer Deposits	(8,900)	1,495
Accrued Taxes, Net	(6,888)	33,976
Fuel Over/Under Recovery, Net	(13,512)	75,097
Other Current Assets	597	1,655
Other Current Liabilities	(22,228)	(19,221)
Net Cash Flows From (Used For) Operating Activities	(30,543)	78,707
INVESTING ACTIVITIES		
Construction Expenditures	(151,973)	(91,617)
Change in Other Cash Deposits, Net	(12,896)	6
Other	3,109	-
Net Cash Flows Used For Investing Activities	(161,760)	(91,611)
FINANCING ACTIVITIES		
Capital Contribution from Parent	40,000	-
Issuance of Long-term Debt – Nonaffiliated	12,495	-
Change in Advances from Affiliates, Net	139,916	63,948
Retirement of Long-term Debt – Affiliated	-	(50,000)
Principal Payments for Capital Lease Obligations	(745)	(457)
Dividends Paid on Cumulative Preferred Stock	(106)	(106)
Net Cash Flows From Financing Activities	191,560	13,385
Net Increase (Decrease) in Cash and Cash Equivalents	(743)	481
Cash and Cash Equivalents at Beginning of Period	1,651	1,520
Cash and Cash Equivalents at End of Period	$ 908	$ 2,001
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 21,339	$ 17,461
Net Cash Paid (Received) for Income Taxes	(2,353)	5,656
Noncash Acquisitions Under Capital Leases	434	1,780

Construction Expenditures Included in Accounts Payable at June 30,	21,261	5,943

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

Results of Operations

Second Quarter of 2007 Compared to Second Quarter of 2006

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

Second Quarter of 2006		$ 28
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	(28)	
Transmission Revenues	(1)	
Other	(3)	
Total Change in Gross Margin		(32)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(4)	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	(1)	
Other Income	2	
Interest Expense	(3)	
Total Change in Operating Expenses and Other		(8)
Income Tax Expense		14
Second Quarter of 2007		$ 2

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

Net Income decreased $26 million to $2 million in 2007. The key drivers of the decrease were a $32 million decrease in Gross Margin and an $8 million increase in Operating Expenses and Other, partially offset by a $14 million decrease in Income Tax Expense.

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

- Retail and Off-system Sales Margins decreased $28 million primarily due to a $25 million provision related to a SWEPCo Texas fuel reconciliation proceeding. See "SWEPCo Fuel Reconciliation – Texas" section of Note 3.
- Other revenues decreased $3 million primarily due to a $4 million decrease in revenue from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to outside parties. The decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million due to a $7 million increase in generation operation and maintenance expenses and a $4 million increase in distribution expenses due to higher overhead line maintenance, partially offset by a $5 million decrease in expenses primarily resulting from decreased coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, due to planned and forced outages at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation, a nonaffiliated entity.
- Interest Expense increased $3 million primarily due to increased borrowings.

Income Taxes

Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Reconciliation of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2007
Net Income
(in millions)

Six Months Ended June 30, 2006		$	46
Changes in Gross Margin:			
Retail and Off-system Sales Margins (a)	(29)		
Transmission Revenues	(1)		
Other	(8)		
Total Change in Gross Margin			(38)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(10)		
Depreciation and Amortization	(3)		
Taxes Other Than Income Taxes	(1)		
Other Income	3		
Interest Expense	(6)		
Total Change in Operating Expenses and Other			(17)
Income Tax Expense			20
Six Months Ended June 30, 2007		$	11

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

Net Income decreased $35 million to $11 million in 2007. The key drivers of the decrease were a $38 million decrease in Gross Margin and a $17 million increase in Operating Expenses and Other, offset by a $20 million decrease in Income Tax Expense.

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

·

Retail and Off-system Sales Margins decreased $29 million primarily due to a $25 million provision related to a SWEPCo Texas fuel reconciliation proceeding. See “SWEPCo Fuel Reconciliation – Texas” section of Note 3.

- Other revenues decreased $8 million primarily due to a $6 million decrease in revenue from coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, to outside parties and a $2 million decrease in gains on sales of emission allowances. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $10 million primarily due to an $8 million increase in generation operation and maintenance, a $5 million increase in distribution expenses due to higher overhead line maintenance and a $3 million increase in transmission expenses related to higher SPP administration fees, partially offset by a $6 million decrease in expenses primarily resulting from decreased coal deliveries from SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC, due to planned and forced outages at the Dolet Hills Generating Station, which is jointly-owned by SWEPCo and Cleco Corporation, a nonaffiliated entity.
- Interest Expense increased $6 million primarily due to increased borrowings.

Income Taxes

Income Tax Expense decreased $20 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the six months ended June 30, 2007 and 2006 were as follows:

	2007	**2006**
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,618	$ 3,049
Cash Flows From (Used For):		
Operating Activities	120,597	76,154
Investing Activities	(253,267)	(123,275)
Financing Activities	131,610	46,180
Net Decrease in Cash and Cash Equivalents	(1,060)	(941)
Cash and Cash Equivalents at End of Period	$ 1,558	$ 2,108

Operating Activities

Net Cash Flows From Operating Activities were $121 million in 2007. SWEPCo produced Net Income of $11 million during the period and noncash expense items of $69 million for Depreciation and Amortization and $25 million related to the Provision for Fuel Disallowance recorded as the result of an ALJ ruling in SWEPCo's Texas fuel reconciliation proceeding. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $36 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The $27 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $20 million inflow from Margin Deposits was due to decreased trading-related deposits resulting from normal trading activities.

Net Cash Flows From Operating Activities were $76 million in 2006. SWEPCo produced Net Income of $46 million during the period and noncash expense items of $66 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 relates to a number of items. The $60 million inflow from Accounts Payable was the result of higher energy purchases. The $53 million outflow from Margin Deposits was due to increased trading-related deposits resulting from the amended SIA. In addition, SWEPCo's $37 million inflow related to Fuel Over/Under Recovery, Net was primarily due to the new fuel surcharges effective December 2005 in its Arkansas service territory and in January 2006 in its Texas service territory. The $23 million outflow from Fuel, Materials and Supplies was the result of increased fuel purchases.

Investing Activities

Cash Flows Used For Investing Activities during 2007 and 2006 were $253 million and $123 million, respectively. The $250 million of cash flows for Construction Expenditures during 2007 were primarily related to new generation facilities. The cash flows during 2006 were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash Flows From Financing Activities were $132 million during 2007. SWEPCo issued $250 million of Senior Unsecured Notes and had a net decrease of $135 million in borrowings from the Utility Money Pool. SWEPCo received $25 million of capital contributions from Parent Company.

Cash Flows From Financing Activities were $46 million during 2006. SWEPCo refinanced $82 million of Pollution Control Bonds and retired $87 million of long-term debt. SWEPCo had a net increase of $65 million in borrowings from the Utility Money Pool and paid $20 million in common stock dividends.

Financing Activity

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

Issuances

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

Senior Unsecured
Notes

Retirements

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Nonaffiliated	$	3,109	4.47	2011
Notes Payable – Nonaffiliated		4,000	6.36	2007
Notes Payable – Nonaffiliated		1,500	Variable	2008

Liquidity

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

Summary Obligation Information

A summary of SWEPCo's contractual obligations is included in its 2006 Annual Report and has not changed significantly from year-end other than the debt issuance and retirements discussed in "Cash Flow" and "Financing Activity" above and Energy and Capacity Purchase Contracts. Effective January 1, 2007, SWEPCo transferred a significant amount of ERCOT energy marketing contracts to AEP Energy Partners (AEPEP), thereby decreasing its future obligations in Energy and Capacity Purchase Contracts. See "ERCOT Contracts Transferred to AEPEP" section of Note 1.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, SWEPCo cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on pending litigation and regulatory proceedings, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2006 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. Adverse results in these proceedings have the potential to materially affect SWEPCo's results of operations, financial condition and cash flows.

New Generation

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct new generation to satisfy the demands of its customers. Plans include the construction of up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and a 480 MW combined-cycle natural gas fired intermediate plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build the Turk plant, a new 600

MW base load coal plant, with a 73% ownership share, in Hempstead County, Arkansas by 2011 to meet the long-term generation needs of its customers. Preliminary cost estimates for SWEPCo's share of these new facilities are approximately $1.4 billion (this total includes all three plants, but excludes the related transmission investment and AFUDC). Expenditures related to construction of all of these facilities are expected to total $349 million in 2007. These new facilities are subject to regulatory approvals from SWEPCo's three state commissions. Mattison plant, the peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions. Mattison plant, Units 3 and 4 began commercial operation in July 2007, with the remaining two units scheduled for completion in December 2007. All four units of the Mattison plant are expected to be completed in advance of the originally planned 2008 commercial operation date. Construction is expected to begin in the second half of 2007 on the base load facility and in 2008 on the intermediate facility, both upon approval from SWEPCo's three state commissions.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2006 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on SWEPCo.

MTM Risk Management Contract Net Assets

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

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

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ 64,354	$ 8	$ 64,362
Noncurrent Assets	10,929	50	10,979
Total MTM Derivative Contract Assets	75,283	58	75,341
Current Liabilities	(51,054)	(12)	(51,066)
Noncurrent Liabilities	(7,822)	-	(7,822)
Total MTM Derivative Contract Liabilities	(58,876)	(12)	(58,888)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 16,407	$ 46	$ 16,453

MTM Risk Management Contract Net Assets Six Months Ended June 30, 2007 (in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 20,166
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(2,885)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	1,853
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(2,727)
Total MTM Risk Management Contract Net Assets	16,407
Net Cash Flow Hedge Contracts	46
Total MTM Risk Management Contract Net Assets at June 30, 2007	$ 16,453

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

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

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

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

The following table presents:

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

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

	Remainder 2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted – Exchange Traded Contracts	$ (10,100)	$ 1,544	$ (247)	$ -	$ -	$ -	$ (8,803)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	21,341	4,080	(711)	-	-	-	24,710
Prices Based on Models and Other Valuation Methods (b)	(1,494)	521	1,471	2	-	-	500
Total	$ 9,747	$ 6,145	$ 513	$ 2	$ -	$ -	$ 16,407

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

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

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

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

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

Management uses forward contracts and collars as cash flow hedges to lock in prices on certain transactions denominated in foreign currencies where deemed necessary. Management does not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on the Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2006 to June 30, 2007. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2007
(in thousands)

	Interest Rate	Foreign Currency	Total
Beginning Balance in AOCI December 31, 2006	$ (6,435)	$ 25	$ (6,410)
Changes in Fair Value	(1,019)	549	(470)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	391	-	391
Ending Balance in AOCI June 30, 2007	$ (7,063)	$ 574	$ (6,489)

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $249 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates Value at Risk (VaR) to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2007, a near term typical change in commodity prices is not expected to have a material effect on results of operations, cash flows or financial condition.

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

Six Months Ended June 30, 2007 (in thousands)				Twelve Months Ended December 31, 2006 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$118	$245	$97	$25	$447	$2,171	$794	$68

The High VaR for the twelve months ended December 31, 2006 occurred in the fourth quarter due to volatility in the ERCOT region.

VaR Associated with Debt Outstanding

Management also utilizes a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to exposure to interest rates primarily related to long-term debt with fixed interest rates was $44 million and $25 million at June 30, 2007 and December 31, 2006, respectively. Management would not expect to liquidate the entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect results of operations or consolidated financial position.

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

	Three Months Ended		Six Months Ended	
	2007	**2006**	**2007**	**2006**
REVENUES				
Electric Generation, Transmission and Distribution	$ 329,250	$ 349,650	$ 656,534	$ 643,643
Sales to AEP Affiliates	16,237	9,414	32,652	20,179
Other	535	420	935	794
TOTAL	346,022	359,484	690,121	664,616
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	125,994	118,271	237,981	208,932
Purchased Electricity for Resale	56,870	44,884	109,368	74,102
Purchased Electricity from AEP Affiliates	16,085	16,826	39,002	40,163
Other Operation	50,204	53,216	103,987	102,916
Maintenance	29,721	22,231	56,060	46,888
Depreciation and Amortization	34,668	32,959	68,790	65,576
Taxes Other Than Income Taxes	17,540	16,165	33,531	32,147
TOTAL	331,082	304,552	648,719	570,724
OPERATING INCOME	14,940	54,932	41,402	93,892
Other Income	3,338	840	5,434	1,568
Interest Expense	(17,235)	(14,073)	(32,725)	(26,844)
INCOME BEFORE INCOME TAXES AND MINORITY INTEREST EXPENSE	1,043	41,699	14,111	68,616
Income Tax Expense (Credit)	(1,553)	12,491	1,068	21,314
Minority Interest Expense	972	896	1,814	1,118
NET INCOME	1,624	28,312	11,229	46,184
Preferred Stock Dividend Requirements	57	58	114	115
EARNINGS APPLICABLE TO COMMON STOCK	$ 1,567	$ 28,254	$ 11,115	$ 46,069

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 135,660	$ 245,003	$ 407,844	$ (6,129)	$ 782,378
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(115)		(115)
TOTAL					762,263
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $519				964	964
NET INCOME			46,184		46,184
TOTAL COMPREHENSIVE INCOME					47,148
JUNE 30, 2006	$ 135,660	$ 245,003	$ 433,913	$ (5,165)	$ 809,411
DECEMBER 31, 2006	$ 135,660	$ 245,003	$ 459,338	$ (18,799)	$ 821,202
FIN 48 Adoption, Net of Tax			(1,642)		(1,642)
Capital Contribution from Parent Company		25,000			25,000
Preferred Stock Dividends			(114)		(114)
TOTAL					844,446
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $172				(79)	(79)
NET INCOME			11,229		11,229
TOTAL COMPREHENSIVE INCOME					11,150
JUNE 30, 2007	$ 135,660	$ 270,003	$ 468,811	$ (18,878)	$ 855,596

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,558	$ 2,618
Accounts Receivable:		
Customers	66,047	88,245
Affiliated Companies	54,004	59,679
Miscellaneous	9,473	8,595
Allowance for Uncollectible Accounts	(32)	(130)
Total Accounts Receivable	129,492	156,389
Fuel	77,717	69,426
Materials and Supplies	48,847	46,001
Risk Management Assets	64,362	120,036
Margin Deposits	21,940	41,579
Prepayments and Other	22,284	18,256
TOTAL	366,200	454,305
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,596,040	1,576,200
Transmission	710,732	668,008
Distribution	1,279,426	1,228,948
Other	615,126	595,429
Construction Work in Progress	392,402	259,662
Total	4,593,726	4,328,247
Accumulated Depreciation and Amortization	1,884,582	1,834,145
TOTAL - NET	2,709,144	2,494,102
OTHER NONCURRENT ASSETS		
Regulatory Assets	138,155	156,420
Long-term Risk Management Assets	10,979	20,531
Employee Benefits and Pension Assets	24,576	26,029
Deferred Charges and Other	62,266	39,581
TOTAL	235,976	242,561
TOTAL ASSETS	$ 3,311,320	$ 3,190,968

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 53,955	$ 188,965
Accounts Payable:		
General	157,564	140,424
Affiliated Companies	70,842	68,680
Short-term Debt – Nonaffiliated	22,373	17,143
Long-term Debt Due Within One Year – Nonaffiliated	97,406	102,312
Risk Management Liabilities	51,066	109,578
Customer Deposits	38,233	48,277
Accrued Taxes	67,335	31,591
Regulatory Liability for Over-Recovered Fuel Costs	51,805	26,012
Other	75,835	85,086
TOTAL	686,414	818,068
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	819,450	576,694
Long-term Debt – Affiliated	50,000	50,000
Long-term Risk Management Liabilities	7,822	14,083
Deferred Income Taxes	348,760	374,548
Regulatory Liabilities and Deferred Investment Tax Credits	339,243	346,774
Deferred Credits and Other	197,615	183,087
TOTAL	1,762,890	1,545,186
TOTAL LIABILITIES	2,449,304	2,363,254
Minority Interest	1,723	1,815
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	270,003	245,003
Retained Earnings	468,811	459,338
Accumulated Other Comprehensive Income (Loss)	(18,878)	(18,799)
TOTAL	855,596	821,202
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,311,320	$ 3,190,968

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2007	2006
OPERATING ACTIVITIES		
Net Income	$ 11,229	$ 46,184
Adjustments for Noncash Items:		
Depreciation and Amortization	68,790	65,576
Deferred Income Taxes	(21,658)	(15,511)
Provision for Fuel Disallowance	24,500	-
Mark-to-Market of Risk Management Contracts	3,759	(14,213)
Deferred Property Taxes	(19,210)	(18,593)
Change in Other Noncurrent Assets	(107)	16,538
Change in Other Noncurrent Liabilities	(7,932)	(16,419)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	26,897	(15,662)
Fuel, Materials and Supplies	(11,126)	(23,003)
Margin Deposits	19,639	(52,838)
Accounts Payable	8,388	60,158
Customer Deposits	(10,044)	3,763
Accrued Taxes, Net	36,445	19,153
Fuel Over/Under Recovery, Net	1,293	37,377
Other Current Assets	1,266	3,560
Other Current Liabilities	(11,532)	(19,916)
Net Cash Flows From Operating Activities	120,597	76,154
INVESTING ACTIVITIES		
Construction Expenditures	(250,409)	(122,616)
Other	(2,858)	(659)
Net Cash Flows Used For Investing Activities	(253,267)	(123,275)
FINANCING ACTIVITIES		
Capital Contribution from Parent	25,000	-
Issuance of Long-term Debt – Nonaffiliated	247,496	80,593
Change in Short-term Debt, Net – Nonaffiliated	5,230	8,855
Change in Advances from Affiliates, Net	(135,010)	64,873
Retirement of Long-term Debt – Nonaffiliated	(8,609)	(86,594)
Principal Payments for Capital Lease Obligations	(2,383)	(1,432)
Dividends Paid on Common Stock	-	(20,000)
Dividends Paid on Cumulative Preferred Stock	(114)	(115)
Net Cash Flows From Financing Activities	131,610	46,180
Net Decrease in Cash and Cash Equivalents	(1,060)	(941)
Cash and Cash Equivalents at Beginning of Period	2,618	3,049
Cash and Cash Equivalents at End of Period	$ 1,558	$ 2,108
SUPPLEMENTARY INFORMATION		

Cash Paid for Interest, Net of Capitalized Amounts	$ 25,876	$ 24,840
Net Cash Paid for Income Taxes	10,617	42,788
Noncash Acquisitions Under Capital Leases	6,511	5,537
Construction Expenditures Included in Accounts Payable at June 30,	38,630	8,326

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations, financial position and cash flows for the interim periods for each Registrant Subsidiary. The results of operations for the six months ended June 30, 2007 are not necessarily indicative of results that may be expected for the year ending December 31, 2007. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2006 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2006 as filed with the SEC on February 28, 2007.

Property, Plant and Equipment and Equity Investments

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

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

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

Revenue Recognition

Traditional Electricity Supply and Delivery Activities

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

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

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

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

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

Energy Marketing and Risk Management Activities

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

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

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

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

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

Components	June 30, 2007	December 31, 2006
	(in thousands)	
Cash Flow Hedges:		
APCo	$ 2,063	$ (2,547)
CSPCo	4,067	3,398
I&M	(7,756)	(8,962)
OPCo	8,233	7,262
PSO	(979)	(1,070)
SWEPCo	(6,489)	(6,410)
SFAS 158 Costs:		
APCo	$ (40,999)	$ (52,244)
CSPCo	(25,386)	(25,386)
I&M	(6,089)	(6,089)
OPCo	(64,025)	(64,025)
SWEPCo	(12,389)	(12,389)

Related Party Transactions

Lawrenceburg Unit Power Agreement (UPA) between CSPCo and AEGCo

In March 2007, CSPCo and AEGCo entered into a 10-year UPA for the entire output from the Lawrenceburg Plant effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional 2-year period. I&M operates the plant under an agreement with AEGCo.

Under the UPA, CSPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

CSPCo paid AEGCo $15.9 million in the second quarter of 2007. On its 2007 Condensed Consolidated Statement of Income, CSPCo recorded these purchases in Other Operation expense for the capacity and depreciation portion, and in Purchased Electricity from AEP Affiliates for the variable cost portion.

ERCOT Contracts Transferred to AEPEP

Effective January 1, 2007, PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEPEP and entered into intercompany financial and physical purchase and sale agreements with AEPEP. This was done to lock in PSO and SWEPCo's margins on ERCOT trading and marketing contracts and to transfer the future associated commodity price and credit risk to AEPEP. The contracts will mature over the next three years.

PSO and SWEPCo have historically presented third party ERCOT trading and marketing activity on a net basis in Revenues - Electric Generation, Transmission and Distribution. The applicable ERCOT third party trading and marketing contracts that were not transferred to AEPEP will remain until maturity on PSO and SWEPCo and will be presented on a net basis in Sales to AEP Affiliates on PSO's and SWEPCo's Statements of Income.

The following table indicates the sales to AEPEP and the amounts reclassified from third party to affiliate:

	For the Three Months Ended June 30, 2007		
Company	Net Settlement With AEPEP	Third Party Amounts Reclassified to Affiliate (in thousands)	Net Amount included in Sales to AEP Affiliates
PSO	$ 33,293	$ (30,307)	$ 2,986
SWEPCo	46,678	(43,160)	3,518

	For the Six Months Ended June 30, 2007		
Company	Net Settlement With AEPEP	Third Party Amounts Reclassified to Affiliate (in thousands)	Net Amount included in Sales to AEP Affiliates
PSO	$ 76,443	$ (66,144)	$ 10,299
SWEPCo	93,554	(81,419)	12,135

The following table indicates the affiliated portion of risk management assets and liabilities reflected on PSO's and SWEPCo's balance sheets associated with these contracts:

	As of June 30, 2007	
	PSO	SWEPCo
Current	(in thousands)	
Risk Management Assets	$ 12,513	$ 14,743
Risk Management Liabilities	(1,894)	(2,231)
Noncurrent		
Long-term Risk Management Assets	$ 943	$ 1,111
Long-term Risk Management Liabilities	(2,946)	(3,471)

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo's and approximately 3% of TNC's businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007 and were recorded at net book value of $11.6 million. The Arkansas Public Service Commission's approval requires SWEPCo to amend its fuel recovery tariff so that Arkansas customers do not pay the incremental cost of serving the additional load.

Reclassifications

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

On their statements of income, the Registrant Subsidiaries reclassified regulatory credits related to regulatory asset cost deferral on ARO from Depreciation and Amortization to Other Operation and Maintenance to offset the ARO accretion expense. The following table shows the credits reclassified by the Registrant Subsidiaries in 2006:

Company	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006
	(in thousands)	
APCo	$ 302	$ 598
I&M	6,118	11,707

2. <u>NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM</u>

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of new pronouncements issued or implemented in 2007 and standards issued but not implemented that management has determined relate to the Registrant Subsidiaries' operations.

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

SFAS 157 is effective for interim and annual periods in fiscal years beginning after November 15, 2007. Management expects that the adoption of this standard will impact MTM valuations of certain contracts, but is unable to quantify the effect. Although the statement is applied prospectively upon adoption, the effect of certain transactions is applied retrospectively as of the beginning of the fiscal year of application, with a cumulative effect adjustment to the appropriate balance sheet items. The Registrant Subsidiaries will adopt SFAS 157 effective January 1, 2008.

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

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

SFAS 159 is effective for annual periods in fiscal years beginning after November 15, 2007. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. In the event the Registrant Subsidiaries elect the fair value option promulgated by this standard, the valuations of certain assets and liabilities may be impacted. The statement is applied prospectively upon adoption. The Registrant Subsidiaries will adopt SFAS 159 effective January 1, 2008. Management expects the adoption of this standard to have an immaterial impact on the financial statements.

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

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

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

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

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. The Registrant Subsidiaries adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable (favorable) adjustment to retained earnings as follows:

Company		**(in thousands)**
APCo	$	2,685
CSPCo		3,022
I&M		(327)

OPCo	5,380
PSO	386
SWEPCo	1,642

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

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

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

Future Accounting Changes

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

EXTRAORDINARY ITEM

APCo recorded an extraordinary loss of $118 million ($79 million, net of tax) during the second quarter of 2007 for the establishment of regulatory assets and liabilities related to the Virginia generation operations. In 2000, APCo discontinued SFAS 71 regulatory accounting for the Virginia jurisdiction due to the passage of legislation for customer choice and deregulation. In April 2007, Virginia passed legislation to establish electric regulation again. See "Virginia Restructuring" in Note 3.

3. RATE MATTERS

As discussed in the 2006 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2006 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations, cash flows and possibly financial condition. The following discusses ratemaking developments in 2007 and updates the 2006 Annual Report.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans – Affecting CSPCo and OPCo

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs. Pursuant to the RSPs, CSPCo and OPCo implemented these proposed increases effective with the first billing cycle in May 2007. These increases are subject to refund until the PUCO issues a final order in the matter. The PUCO staff and intervenors have proposed disallowances. The revenues collected, subject to refund, are immaterial through June 30, 2007. Management is unable to determine the impact, if any, of potential refunds or rider reductions on future results of operations and cash flows. The hearing is completed and initial post-hearing and reply briefs have been filed. A final order is expected in late third quarter or early fourth quarter of 2007.

In March 2007, CSPCo filed an application under the 4% provision of the RSP to adjust the Power Acquisition Rider (PAR) which was authorized in 2005 by the PUCO in connection with CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio and a new purchase power contract to serve the load. The PUCO approved the requested increase in the PAR, which is expected to increase CSPCo's revenues by $22 million and $38 million for 2007 and 2008, respectively.

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

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio regarding potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Customer Choice Deferrals – Affecting CSPCo and OPCo

As provided in the restructuring settlement agreement approved by the PUCO in 2000, CSPCo and OPCo established regulatory assets for customer choice implementation costs and related carrying costs in excess of $20 million each for recovery in the next general base rate filing which changes distribution rates after December 31, 2007 for OPCo and December 31, 2008 for CSPCo. Pursuant to the RSPs, recovery of these amounts for OPCo was further deferred until the next base rate filing to change distribution rates after the end of the RSP period of December 31, 2008. Through June 30, 2007, CSPCo and OPCo incurred $51 million and $52 million, respectively, of such costs and established regulatory assets of $25 million and $26 million, respectively, for such costs. CSPCo and OPCo each have not recognized $6 million of equity carrying costs, which are recognizable when collected. In 2007, CSPCo and OPCo incurred $2 million each of such costs and established regulatory assets of $1 million each for such costs. Management believes that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure to recover such costs will have an adverse effect on results of operations and cash flows.

Ohio IGCC Plant – Affecting CSPCo and OPCo

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

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. Through June 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered. As of June 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all amounts collected for pre-construction costs, associated with items that may be utilized in IGCC projects to be built by AEP at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

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

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant are $2.2 billion. CSPCo and OPCo may need to request an extension to the 5 year start of construction requirement if the commencement of construction is delayed beyond 2011. In July 2007, CSPCo and OPCo filed a status report with the PUCO referencing APCo's IGCC West Virginia filing. See the "West Virginia IGCC Plant" section within West Virginia Rate Matters of this note.

Distribution Reliability Plan – Affecting CSPCo and OPCo

In January 2006, CSPCo and OPCo initiated a proceeding at the PUCO seeking a new distribution rate rider to fund enhanced distribution reliability programs. In the fourth quarter of 2006, as directed by the PUCO, CSPCo and OPCo filed a proposed enhanced reliability plan. The plan contemplated CSPCo and OPCo recovering approximately $28 million and $43 million, respectively, in additional distribution revenue during an eighteen month period beginning July 2007. In January 2007, the Ohio Consumers' Counsel filed testimony, which argued that CSPCo and OPCo should be required to improve distribution service reliability with funds from their existing rates.

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

Ormet – Affecting CSPCo and OPCo

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, under a PUCO-encouraged settlement agreement. The settlement agreement between CSPCo and OPCo, Ormet, its employees' union and certain other interested parties was approved by the PUCO in November 2006. The settlement agreement provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH to be paid by Ormet for power and a PUCO-approved market price, if higher. The recovery will be accomplished by the amortization of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is insufficient, an increase in RSP generation rates under the additional 4% provision of the RSPs. The $43 per MWH price to be paid by Ormet for generation services is above the industrial RSP generation tariff but below current market prices. In December 2006, CSPCo and OPCo submitted a market price of $47.69 per MWH for 2007, which was approved by the PUCO in June 2007. CSPCo and OPCo have each amortized $3 million of their Ohio Franchise Tax phase-out tax regulatory liability to income through June 30, 2007. If the PUCO approves a lower-than-market price in 2008, it could have an adverse effect on future results of operations and cash flows. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo off-system sales margins, which could have an adverse effect on future results of operations and cash flows.

Texas Rate Matters

SWEPCo Fuel Reconciliation – Texas – Affecting SWEPCo

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations for the three-year reconciliation period ended December 31, 2005. SWEPCo sought, in the proceedings, to include under-recoveries related to the reconciliation period of $50 million. In January 2007, intervenors filed testimony recommending that SWEPCo's reconcilable fuel costs be reduced. The PUCT staff and intervenor disallowances ranged from $10 million to $28 million. In June 2007, an ALJ issued a Proposal for Decision recommending a $17 million disallowance. Results of operations for the second quarter of 2007 were adversely affected by $25 million as a result of reflecting the ALJ's decision. In July 2007, the PUCT orally affirmed the ALJ report. A final order is expected in the third quarter of 2007. Management is unable to predict the ultimate outcome of this proceeding or its additional effect on future results of operations and cash flows.

Virginia Rate Matters

Virginia Restructuring – Affecting APCo

In April 2004, Virginia enacted legislation that amended the Virginia Electric Utility Restructuring Act extending the transition period to market rates for the generation and supply of electricity, including the extension of capped rates, through December 31, 2010. The legislation provided APCo with specified cost recovery opportunities during the extended capped rate period, including two optional bundled general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain unrecovered incremental environmental and reliability costs incurred on and after July 1, 2004. Under the amended restructuring law, APCo continues to have an active fuel clause recovery mechanism in Virginia and continues to practice deferred fuel accounting. Also, under the amended restructuring law, APCo has the right to defer incremental environmental compliance costs and incremental E&R costs for future recovery, to the extent such costs are not being recovered, and amortizes a portion of such deferrals commensurate with their recovery.

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

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

Virginia Base Rate Case – Affecting APCo

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of $225 million to recover increasing costs including the cost of its investment in environmental equipment and a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be trued-up to actual. APCo also proposed to share the off-system sales margins with customers with 40% going to reduce rates and 60% being retained by APCo. This proposed off-system sales fuel rate credit, which was estimated to be $27 million, partially offsets the $225 million requested increase in base rates for a net increase in base rate revenues of $198 million. The major components of the $225 million base rate request included $73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, $60 million mainly due to projected net environmental plant additions through September 30, 2007 and $48 million for return on equity.

In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the net requested base rate increase of $198 million into effect on October 2, 2006, subject to refund. The $198 million base rate increase that was collected, subject to refund, includes recovery of incremental E&R costs projected to be incurred during the rate year beginning October 2006. These incremental E&R costs can be deferred and recovered through the E&R surcharge mechanism if not recovered through base rates. In October 2006, the Virginia SCC staff filed its direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors recommended base rate increases ranging from $42 million to $112 million. APCo filed rebuttal testimony in November 2006. Hearings were held in December 2006.

In March 2007, the Hearing Examiner issued a report recommending a $76 million increase in APCo's base rates and a $45 million credit to the fuel factor for off-system sales margins resulting in a net $31 million recommended rate increase. In May 2007, the Virginia SCC issued a final order approving an overall annual base rate increase of $24 million effective as of October 2006. The final order approved a return on equity of 10.0% and limited forward-looking ratemaking adjustments to June 30, 2006 as opposed to September 30, 2007 as proposed. In addition, the final order excluded a portion of APCo's requested E&R costs in base rates. However, APCo was able to defer unrecovered incremental E&R costs incurred after October 1, 2006 and will recover those costs through the E&R surcharge mechanism. The order also provided for a retroactive annual reduction in depreciation to January 1, 2006 of approximately $11 million per year and a deferral and recovery of ARO costs over 10 years. The final order further provides that off-system sales margins of $101 million be credited to customers through a separate base rate margin rider which is not trued-up to actual margins. The final order did not implement the minimum 25% sharing percentage for off-system sales margins embodied in the new re-regulation legislation, which is effective with the first fuel clause filing after July 1, 2007. This sharing requirement in the new re-regulation legislation also includes a true-up to actual off-system sales margins.

As a result of the final order, APCo's second quarter pretax earnings decreased by approximately $3 million due to a decrease in revenues of $42 million net of a recorded provision for refund and related interest offset by (a) a $15 million net effect from the deferral of unrecovered incremental E&R costs incurred from October 1, 2006 through June 30, 2007 to be collected in a future E&R filing, (b) a $9 million net deferral of ARO costs to be recovered over 10 years and (c) a $15 million retroactive decrease in depreciation expense. In addition to the favorable effect of the base rate increase in the second half of 2007, APCo expects to defer for future recovery unrecovered incremental E&R costs incurred of $20 million to $25 million and reduce depreciation and amortization expense by a net $5 million. APCo will complete the refund by August 2007. APCo's Other Current Liabilities includes accrued refunds of $127 million and $22 million as of June 30, 2007 and December 31, 2006, respectively. Management expects pretax earnings for 2007 to be favorably affected by the ordered May 2007 rate increase.

Virginia E&R Costs Recovery Filing – Affecting APCo

In July 2007, APCo filed a request with the Virginia SCC seeking recovery over the twelve months beginning December 1, 2007 of approximately $60 million of unrecovered incremental E&R costs inclusive of carrying costs thereon incurred from October 1, 2005 through September 30, 2006. APCo will file for recovery in 2008 of E&R cost deferrals incurred and recorded after September 30, 2006.

Virginia Fuel Clause Filing – Affecting APCo

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

West Virginia IGCC Plant – Affecting APCo

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

West Virginia Rate Matters

APCo and WPCo ENEC Filing – Affecting APCo

In April 2007, the WVPSC issued an order establishing an investigation and hearing concerning APCo's and WPCo's 2007 Expanded Net Energy Cost (ENEC) compliance filing. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits and other energy/transmission items. In the March 2007 ENEC joint filing, APCo and WPCo filed for an increase of approximately $91 million including a $65 million increase in ENEC and a $26 million increase in construction cost surcharges to become effective July 1, 2007. In June 2007, the WVPSC issued an order approving, without modification, a joint stipulation and agreement for settlement reached among the parties. The settlement agreement provided for an increase in annual non-base revenues of approximately $77 million effective July 1, 2007. This annual revenue increase primarily includes $50 million of ENEC and $26 million of construction cost surcharges. The ENEC portion of the increase is subject to a true-up, which should avoid an under-recovery of ENEC costs if they exceed the $50 million.

West Virginia IGCC Plant – Affecting APCo

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

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

Indiana Rate Matters

Indiana Depreciation Study Filing – Affecting I&M

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. The filing included a settlement agreement entered into with the Indiana Office of the Utility Consumer Counsel (OUCC) that would provide direct benefits to I&M's customers if new lower depreciation rates were approved by the IURC. The direct benefits would include a $5 million credit to fuel costs and an approximate $8 million smart metering pilot program. In addition, if the agreement were to be approved, I&M would initiate a general rate proceeding on or before July 1, 2007 and initiate two studies, one to investigate a general smart metering program and the other to study the market viability of demand side management programs. Based on the depreciation study included in the filing, I&M recommended and the settlement agreed to a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately $69 million reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition was not a request for a change in customers’ electric service rates. As proposed, the book depreciation reduction would increase earnings, but would not impact cash flows until rates are revised. Base and fuel rates were frozen in Indiana through June 30, 2007. The IURC held a public hearing in April 2007. In June 2007, the IURC approved the settlement agreement, but modified the effective date of the new depreciation rates upon the filing by I&M of a general rate petition. See “Indiana Rate Filing” section below. On June 19, 2007, I&M and the OUCC notified the IURC the parties would accept the modification to the settlement agreement and I&M filed its rate petition.

The settlement agreement modification reduced book depreciation rates, which will result in an increase of $37 million in pretax earnings for the period June 19, 2007 to December 31, 2007. The $37 million increase is partially offset by a $5 million regulatory liability, recorded in June 2007, to provide for the agreed-upon fuel credit. I&M’s approved depreciation rates are subject to further review in the general rate case. I&M’s earnings will continue to benefit until the base rates are revised to include lower depreciation rates, at which time cash flows will be adversely affected. Management expects new base rates will become effective in late 2008 or early 2009.

Indiana Rate Filing – Affecting I&M

In June 2007, I&M filed a rate notification petition with the IURC regarding its intent to file for a base rate increase with a proposed test year ended September 30, 2007. The petition indicated, among other things, the filing would include a request to implement rate tracker mechanisms for certain variable components of the cost of service including AEP Power Pool capacity settlements, PJM RTO costs, reliability enhancement costs, DSM/energy efficiency program costs, off-system sales margins, and net environmental compliance costs. The petition requests the IURC to approve the test year period and the inclusion of the above trackers in the rate filing. Management expects to file the case in late 2007 or early 2008 with a decision expected in late 2008 or early 2009.

Indiana Rate Cap – Affecting I&M

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

Oklahoma Rate Matters

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

In 2002, PSO under-recovered $44 million of purchased power costs through its fuel clause resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO proposed collection of those reallocated costs over eighteen months. In August 2003, the OCC staff filed testimony recommending PSO recover $42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by $2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the $42 million of under-recovered fuel with the proposed reallocation of off-system sales margins of $27 million to $37 million and with $9 million of purchased power reallocation attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the $9 million of reallocated purchased power costs assigned to wholesale customers had been refunded, thus removing that issue from its recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. The United States District Court for the Western District of Texas issued orders in September 2005 regarding a TNC fuel proceeding and in August 2006 regarding a TCC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling. The United States Court of Appeals for the Fifth Circuit, issued a decision in December 2006 regarding the TNC fuel proceeding that affirmed the United States District Court ruling. In April 2007, the PUCT petitioned the United States Supreme Court for a review of the Court of Appeal's order.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals other than the staff's original recommendation that PSO be allowed to recover the $42 million over three years and will defend its right to recover its under-recovered fuel balance. Management believes that if the position taken by the federal courts in the Texas proceeding is applied to PSO's case, then the OCC should be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party could file a complaint at the FERC alleging the allocation of off-system sales margins to PSO is improper, which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. However, to date, there has been no claim asserted at the FERC that AEP deviated from the FERC approved allocation methodologies, but even if one were asserted, management believes that the OCC or another party would not prevail.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. The OCC staff filed testimony finding no disallowances in the test year data. The Attorney General of Oklahoma filed testimony stating that they could not determine if PSO's gas procurement activities were prudent, but did not include a recommended disallowance. However, an intervenor filed testimony in June 2006 proposing the disallowance of $22 million in fuel costs based on a historical review of potential hedging opportunities that he alleges existed during the year. A hearing was held in August 2006 and management expects a recommendation from the ALJ in the second half of 2007.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to the required biennial reviews. PSO filed its testimony in June 2007 covering the year 2005.

In May 2007, PSO filed an application to adjust its fuel/purchase power rates. In the filing, PSO netted the $42 million of under-recovered pre-2002 reallocated purchased power costs against their current $48 million over-recovered fuel balance. In oral discussions, the OCC staff did not oppose the netting of the balances. The $6 million net over-recovered fuel/purchased power cost deferral balance will be refunded over the twelve month period beginning June 2007. To date, no party has objected to the offset.

Management cannot predict the outcome of the pending fuel and purchased power costs and prudence reviews, planned future reviews or the current fuel adjustment clause filing, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the pre-2002 reallocation of purchased power costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

Oklahoma Rate Filing – Affecting PSO

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

In March 2007, the OCC staff and various intervenors filed testimony. The recommendations were base rate reductions that ranged from $18 million to $52 million. The recommended returns on equity ranged from 9.25% to 10.09%. These recommendations included reductions in depreciation expense of approximately $25 million, which has no earnings impact. The OCC staff filed testimony supporting a formula rate plan, generally similar to the one proposed by PSO. In April 2007, PSO filed rebuttal testimony regarding various issues raised by the OCC staff and the intervenors. In connection with the filing of rebuttal testimony, PSO reduced its base rate request by $2 million. The ALJ issued a report in May 2007 recommending a 10.5% return on equity, but did not compute an overall revenue requirement. The ALJ's report did not recommend adopting a formula rate plan, but did recommend recovery through a rider of certain generation and transmission projects' financing costs during construction. However, the report also contained an alternative recommendation that the OCC could delay a decision on the rider and take up this issue in PSO's application seeking regulatory approval of the coal-fueled generating unit. The OCC's discussions during deliberations have centered around a return on equity of 9.75%. PSO implemented interim rates, subject to refund, for residential customers beginning July 2007. The interim rate implements a key provision of the rate case on which there seems to be agreement at the OCC, and is estimated to increase revenues by approximately $4 million in 2007 and $9 million on an annual basis. Other components of the rate case will be implemented once the OCC issues a final order, which is expected in early August 2007.

Management is unable to predict the final outcome of these proceedings. However, if rates are not increased in an amount sufficient to recover expected unavoidable cost increases, future results of operations, cash flows and possibly financial condition could be adversely affected.

Lawton and Peaking Generation Settlement Agreement – Affecting PSO

On November 26, 2003, pursuant to an application by Lawton Cogeneration, L.L.C. (Lawton) seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court (the Court). In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Court issued a decision 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. Hearings were held on the remanded issues in April and May 2006.

In April 2007, all parties in the case filed a settlement agreement with the OCC resolving all issues. The OCC approved the settlement agreement in April 2007. The OCC staff, the Attorney General, the Oklahoma Industrial Energy Consumers and Lawton Cogeneration, L.L.C supported this settlement agreement. The settlement agreement provides for a purchase fee of $35 million to be paid by PSO to Lawton and for Lawton to provide, at PSO's direction, all rights to the Lawton Cogeneration Facility including permits, options and engineering studies. PSO paid the $35 million purchase fee in June 2007 and recorded the purchase fee as a regulatory asset and will recover it through a rider over a three-year period with a carrying charge of 8.25% beginning in September 2007. In addition, PSO will recover through a rider, subject to a $135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service. PSO expects these units will have a substantially lower plant-in-service cost than the proposed Lawton Cogeneration Facility. PSO may request approval from the OCC for recovery of costs exceeding the cost cap if special circumstances occur necessitating a higher level of costs. Such costs will continue to be recovered through the rider until cost recovery occurs through base rates or formula rates in a subsequent proceeding. Under the settlement, PSO must file a rate case within eighteen months of the beginning of recovery through the rider unless the OCC approves a formula-based rate mechanism that provides for recovery of the peaking units. Once the cost recovery for the new peaking units begins in mid-2008, PSO expects annual revenues of an estimated $36 million related to cost recovery of the peaking units and the purchase fee.

Louisiana Rate Matters

Louisiana Compliance Filing – Affecting SWEPCo

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

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

<u>FERC Rate Matters</u>

Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

<u>The FERC PJM Regional Transmission Rate Proceeding</u>

At AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP and other transmission owners for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposed and supported a new PJM rate regime generally referred to as a Highway/Byway rate design.

Parties to the regional rate proceeding proposed the following rate regimes:

- AEP/AP proposed a Highway/Byway rate design in which:
  - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand. The AEP/AP proposal would produce about $125 million in net revenues per year for AEP from users in other zones of PJM.
  - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- Two other utilities, Baltimore Gas & Electric Company (BG&E) and Old Dominion Electric Cooperative (ODEC), proposed a Highway/Byway rate that includes transmission facilities above 200 kV in the Highway rate, which would have produced lower net revenues for AEP than the AEP/AP proposal.
- In another competing Highway/Byway proposal, a group of LSEs proposed rates that would include existing 500 kV and higher voltage facilities and new facilities above 200 kV in the Highway rate, which would also have produced lower net revenues for AEP than the AEP/AP proposal.
- In January 2006, the FERC staff issued testimony and exhibits supporting phase-in of a PJM-wide flat rate or "Postage Stamp" type of rate design that would socialize the cost of all transmission facilities. The proposed rate design would have initially produced much lower net transmission revenues for AEP than the AEP/AP proposal, but could produce slightly higher net revenues when fully phased in.

All of these proposals were challenged by a majority of other transmission owners in the PJM region, who favored continuation of the existing PJM rate design which provides AEP with no compensation for through and out traffic on its east zone transmission system. Hearings were held in April 2006 and the ALJ issued an initial decision in July 2006. The ALJ found the existing PJM zonal rate design to be unjust and determined that it should be replaced. The ALJ found that the Highway/Byway rates proposed by AEP/AP and BG&E/ODEC to be just and reasonable alternatives. The ALJ also found FERC staff's proposed Postage Stamp rate to be just and reasonable and recommended that it be adopted. The ALJ also found that the effective date of the rate change should be April 1, 2006 to coincide with SECA rate elimination. Because the Postage Stamp rate was found to produce greater cost shifts than other proposals, the judge also recommended that the new regional design be phased-in. Without a phase-in, the Postage Stamp method would produce more revenue for AEP than the AEP/AP proposal. However, the proposed phase-in of Postage Stamp rates would delay the full favorable impact of those new regional rates until about 2012.

AEP filed briefs noting exceptions to the initial decision and replies to the exceptions of other parties. AEP argued that a phase-in should not be required. Nevertheless, AEP argued that if the FERC adopts the Postage Stamp rate and a phase-in plan, the revenue collections curtailed by the phase-in should be deferred and paid later with interest.

Since the FERC's decision in 2005 to cease through-and-out rates and replace them temporarily with SECA rates which ceased on April 1, 2006, the AEP East companies increased their retail rates in all states except Indiana and Michigan to recover lost through-and-out transmission service (T&O) and SECA revenues.

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

The AEP East companies presently recover from retail customers approximately 85% of the lost T&O/SECA transmission revenues of $128 million a year. Future results of operations, cash flows and financial condition will continue to be adversely affected in Indiana and Michigan until these lost T&O/SECA transmission revenues are recovered in retail rates.

SECA Revenue Subject to Refund

The AEP East companies ceased collecting T&O revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. APCo's, CSPCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	**(in millions)**	
APCo	$	70.2
CSPCo		38.8

I&M	41.3
OPCo	53.3

Approximately $19 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of AEP's SECA customers. APCo's, CSPCo's, I&M's and OPCo's portions of the reserve are as follows:

Company	(in millions)
APCo	$ 12.0
CSPCo	6.7
I&M	7.0
OPCo	9.1

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

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

SPP Transmission Formula Rate Filing

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

PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. FERC could suspend the effective date until February 1, 2008. The primary impact of the filed revised tariff will be an increase in network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP Zone. If the proposed formula rate and requested return on equity are approved, the 2008 network transmission service revenues from nonaffiliates will increase by approximately $10 million compared to the revenues that would result from the presently approved network transmission rate. PSO and SWEPCo take service under the same rate, and will also incur the increased OATT rates resulting from the filing, but will receive corresponding revenue to offset the increase. This filing will not directly impact retail rates.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

GUARANTEES

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

Letters of Credit

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries’ ordinary course of business. At June 30, 2007, the maximum future payments of the LOCs include $1 million and $4 million for I&M and SWEPCo, respectively, with maturities ranging from December 2007 to March 2008.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately $39 million. As of June 30, 2007, SWEPCo collected approximately $31 million through a rider for final mine closure costs, which is recorded in Deferred Credits and Other on SWEPCo’s Condensed Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 2007, the Registrant Subsidiaries entered into sale agreements including indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At June 30, 2007, 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 was as follows:

Company		**Maximum Potential Loss (in millions)**
APCo	$	8
CSPCo		4
I&M		6
OPCo		8
PSO		5
SWEPCo		6

CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA, certain special interest groups and a number of states allege that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at the AEP System's generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

Under the CAA, if a plant undertakes a major modification that 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 routine maintenance, replacement of degraded equipment or failed components or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to

$27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned), and Stuart (26% owned) Stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Court denied the Federal EPA's request for rehearing, and the Federal EPA and other parties filed a petition for review by the U.S. Supreme Court. In April 2007, the Supreme Court denied the petition for review. The Federal EPA also proposed a rule that would define "emissions increases" in a way that most of the challenged activities would be excluded from NSR.

On April 2, 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo in U.S. District Court for the Southern District of Ohio, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of the NSR proceedings. The court that heard the trial on liability issues will likely issue its decision during the third quarter of 2007. A bench trial on remedy issues, if necessary, is likely to begin in the second half of 2007.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, 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 AEP subsidiaries do not prevail, management believes AEP subsidiaries 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 any of 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.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. SWEPCo filed a response to the complaint in May 2005. A trial in this matter is scheduled for the third quarter of 2007.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007 removing the heat input references from the Welsh permit and clarifying the sulfur content of fuels burned at the plant is limited to 0.5% on an as-received basis. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion.

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

Carbon Dioxide (CO_2) Public Nuisance Claims – Affecting AEP East Companies and AEP West Companies

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

TEM Litigation – Affecting OPCo

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

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

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

In May 2007, the United States Court of Appeals for the Second Circuit ruled that the lower court was correct in finding that TEM breached the PPA and OPCo did not breach the PPA. It also ruled that the lower court applied an incorrect standard in denying OPCo any damages for TEM's breach of the 20-year term of the PPA holding that OPCo is entitled to the benefit of its bargain and that the trial court must determine damages. The Court of Appeals vacated OPCo's $123 million judgment for damages against TEM related to replacement products and remanded the issue for further proceedings.

Coal Transportation Dispute – Affecting PSO

PSO, TCC, TNC, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed 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 2004, 2005, 2006 and the first six months of 2007. The provision was deferred as a regulatory asset under PSO's fuel mechanism and immaterially affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In February 2007, the U.S. District Court granted BNSF's Motion to Reconsider. PSO filed a substantive response to BNSF's motion and BNSF filed a reply. Management continues to work toward mitigating the disputed amounts to the extent possible.

FERC Long-term Contracts – Affecting AEP East Companies and AEP West Companies

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. An ALJ recommended rejection of the complaint, holding that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. In May 2007, the Registrant Subsidiaries, along with other sellers involved in the case, sought review of the Ninth Circuit's decision by the U.S. Supreme Court. The Solicitor General of the United States has asked the Supreme Court for an extension of time, until August 6, 2007, to respond to the petitions for review. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. The Registrant Subsidiaries asserted claims against certain companies that sold power to them, which was resold to the Nevada utilities, seeking to recover a portion of any amounts the Registrant Subsidiaries may owe to the Nevada utilities.

5. ACQUISITION

Darby Electric Generating Station – Affecting CSPCo

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

6. BENEFIT PLANS

The Registrant Subsidiaries participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, the Registrant Subsidiaries participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

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

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2007 and 2006:

	Pension Plans		Other Postretirement Benefit Plans	
	2007	**2006**	**2007**	**2006**
Three Months Ended June 30, 2007 and 2006		(in millions)		
Service Cost	$ 23	$ 24	$ 11	$ 10
Interest Cost	57	57	26	25
Expected Return on Plan Assets	(82)	(83)	(26)	(23)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	14	19	3	5
Net Periodic Benefit Cost	$ 12	$ 17	$ 21	$ 24

	Pension Plans		Other Postretirement Benefit Plans	
	2007	**2006**	**2007**	**2006**

Six Months Ended June 30, 2007 and 2006		(in millions)		
Service Cost	$ 47	$ 48	$ 21	$ 20
Interest Cost	116	114	52	50
Expected Return on Plan Assets	(167)	(166)	(52)	(46)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	29	39	6	10
Net Periodic Benefit Cost	$ 25	$ 35	$ 41	$ 48

The following table provides the net periodic benefit cost (credit) for the plans by Registrant Subsidiary for the three and six months ended June 30, 2007 and 2006:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2007	**2006**	**2007**	**2006**
Three Months Ended June 30, 2007 and 2006		**(in thousands)**		
APCo	$ 842	$ 1,469	$ 3,560	$ 4,489
CSPCo	(258)	205	1,491	1,805
I&M	1,900	2,330	2,531	2,953
OPCo	245	829	2,801	3,396
PSO	424	979	1,430	1,588
SWEPCo	747	1,225	1,419	1,578

	Pension Plans		**Other Postretirement Benefit Plans**	
	2007	**2006**	**2007**	**2006**
Six Months Ended June 30, 2007 and 2006		**(in thousands)**		
APCo	$ 1,684	$ 2,937	$ 7,120	$ 8,978
CSPCo	(515)	410	2,982	3,610
I&M	3,800	4,661	5,061	5,906
OPCo	490	1,655	5,603	6,792
PSO	848	1,956	2,861	3,176
SWEPCo	1,493	2,450	2,838	3,156

7. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. INCOME TAXES

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation approximates a separate return result for each company in the consolidated group.

Audit Status

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

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

FIN 48 Adoption

The Registrant Subsidiaries adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the approximate increase (decrease) in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings was recognized by each Registrant Subsidiary as follows:

Company	**(in thousands)**	
APCo	$	2,685
CSPCo		3,022
I&M		(327)
OPCo		5,380
PSO		386
SWEPCo		1,642

At January 1, 2007, the total amount of unrecognized tax benefits under FIN 48 for each Registrant Subsidiary was as follows:

Company	**(in millions)**	
APCo	$	21.7
CSPCo		25.0
I&M		18.2
OPCo		49.8
PSO		8.9
SWEPCo		7.1

Management believes it is reasonably possible that there will be a net decrease in unrecognized tax benefits due to the settlement of audits and the expiration of statute of limitations within 12 months of the reporting date for each Registrant Subsidiary as follows:

Company	**(in millions)**	
APCo	$	5.5

CSPCo		9.3
I&M		6.0
OPCo		9.0
PSO		4.4
SWEPCo		2.8

At January 1, 2007, the total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant Subsidiary was as follows:

Company	(in millions)	
APCo	$	5.4
CSPCo		13.8
I&M		5.4
OPCo		23.4
PSO		1.2
SWEPCo		1.2

At January 1, 2007, tax positions for each Registrant Subsidiary, for which the ultimate deductibility is highly certain but the timing of such deductibility is uncertain, was as follows:

Company	(in millions)	
APCo	$	13.7
CSPCo		3.9
I&M		10.3
OPCo		14.2
PSO		7.1
SWEPCo		5.1

Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

Prior to the adoption of FIN 48, the Registrant Subsidiaries recorded interest and penalty accruals related to income tax positions in tax accrual accounts. With the adoption of FIN 48, the Registrant Subsidiaries began recognizing interest accruals related to income tax positions in interest expense and penalties in Other Operations. As of January 1, 2007, each Registrant Subsidiary accrued for the payment of uncertain interest and penalties as follows:

Company	(in millions)	
APCo	$	4.6
CSPCo		1.7
I&M		2.8
OPCo		4.3
PSO		2.7
SWEPCo		2.0

Michigan Tax Restructuring (Affecting I&M)

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

I&M is in the process of evaluating the impact of the MBT Act. It is expected that the application of the MBT Act will not materially affect I&M's results of operations, cash flows or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2007 were:

Company	Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:					
APCo	Pollution Control Bonds	$	75,000	Variable	2037
OPCo	Pollution Control Bonds		65,000	4.90	2037
OPCo	Senior Unsecured Notes		400,000	Variable	2010
PSO	Pollution Control Bonds		12,660	4.45	2020
SWEPCo	Senior Unsecured Notes		250,000	5.55	2017

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

Company	Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
APCo	Senior Unsecured Notes	$	125,000	Variable	2007
APCo	Other		6	13.718	2026
OPCo	Notes Payable		2,927	6.81	2008
OPCo	Notes Payable		6,000	6.27	2009
SWEPCo	Notes Payable		3,109	4.47	2011
SWEPCo	Notes Payable		4,000	6.36	2007
SWEPCo	Notes Payable		1,500	Variable	2008

In July 2007, PSO redeemed $13 million of 6.00% Pollution Control Bonds due in 2020.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of June 30, 2007 and December 31, 2006 are included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the six months ended June 30, 2007 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of June 30, 2007	Authorized Short-Term Borrowing Limit
			(in thousands)			
APCo	$ 247,616	$ -	$ 103,925	$ -	$ 247,616	$ 600,000
CSPCo	117,890	35,270	53,692	13,190	64,003	350,000
I&M	100,374	-	60,659	-	14,941	500,000
OPCo	447,335	1,564	209,965	1,564	16,583	600,000
PSO	216,239	-	111,567	-	216,239	300,000
SWEPCo	240,786	48,979	70,927	29,653	53,955	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Six Months Ended June 30, 2007	2006
Maximum Interest Rate	5.46%	5.39%
Minimum Interest Rate	5.30%	4.19%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2007 and 2006 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Six Months Ended June 30, 2007	2006	Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30, 2007	2006
		(in percentage)		
APCo	5.36	4.62	-	5.05
CSPCo	5.37	4.73	5.33	4.91
I&M	5.35	4.76	-	-
OPCo	5.35	4.86	5.43	5.30
PSO	5.36	4.91	-	-
SWEPCo	5.36	4.92	5.34	-

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		June 30, 2007		December 31, 2006	
Company	**Type of Debt**	**Outstanding Amount (in millions)**	**Interest Rate**	**Outstanding Amount (in millions)**	**Interest Rate**
OPCo	Commercial Paper – JMG	$ -	-	$ 1	5.56%
SWEPCo	Line of Credit – Sabine	22	6.20%	17	6.38%

Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.

Sale of Receivables – AEP Credit

In July 2007, AEP extended AEP Credit's sale of receivables agreement. The sale of receivables agreement provides commitments of $600 million from a bank conduit to purchase receivables from AEP Credit. This agreement will expire in November 2007. AEP intends to renew or replace this agreement. AEP Credit purchases accounts receivable through purchase agreements with CSPCo, I&M, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements and (iii) footnotes of each individual registrant. The combined Management's Discussion and Analysis of Registrant Subsidiaries section of the 2006 Annual Report should also be read in conjunction with this report.

Significant Factors

Ohio Restructuring

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Ohio New Generation

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

In April 2006, the PUCO issued an order authorizing CSPCo and OPCo to implement Phase 1 of the cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. Through June 30, 2007, CSPCo and OPCo each recorded pre-construction IGCC regulatory assets of $10 million and each collected the entire $12 million approved by the PUCO. CSPCo and OPCo expect to incur additional pre-construction costs equal to or greater than the $12 million each recovered. As of June 30, 2007, CSPCo and OPCo have recorded a liability of $2 million each for the over-recovered portion. The PUCO indicated that if CSPCo and OPCo have not commenced a continuous course of construction of the IGCC plant within five years of the June 2006 PUCO order, all charges collected for pre-construction costs, associated with items that may be utilized in IGCC projects to be built by AEP at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 until further hearings are held. A date for further rehearings has not been set.

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

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they may delay the start of construction of the IGCC plant. Recent estimates of the cost to build an IGCC plant are $2.2 billion. CSPCo and OPCo may need to request an extension to the 5 year start of construction requirement if the commencement of construction is delayed beyond 2011. In July 2007, CSPCo and OPCo filed a status report with the PUCO referencing APCo's IGCC West Virginia filing.

SECA Revenue Subject to Refund

The AEP East companies ceased collecting T&O revenues in accordance with FERC orders, and collected SECA rates to mitigate the loss of T&O revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund or surcharge. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million. APCo's, CSPCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)	
APCo	$	70.2
CSPCo		38.8
I&M		41.3
OPCo		53.3

Approximately $19 million of these recorded SECA revenues billed by PJM were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

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

Since the implementation of SECA rates in December 2004, the AEP East companies recorded approximately $220 million of gross SECA revenues, subject to refund. In 2006, the AEP East companies provided reserves of $37 million in net refunds for current and future SECA settlements with all of AEP's SECA customers. APCo's, CSPCo's, I&M's and OPCo's portions of the reserve are as follows:

Company	(in millions)	
APCo	$	12.0
CSPCo		6.7
I&M		7.0
OPCo		9.1

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

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

Environmental Matters

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

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

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

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. Several similar complaints were filed in 1999 and thereafter against nonaffiliated utilities including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at the Registrant Subsidiaries' power plants occurred over a 20-year period. A bench trial on the liability issues was held during 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

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

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants have reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in the Duke Energy case.

In April 2007, the U.S. Supreme Court reversed the Fourth Circuit Court of Appeals' decision that had supported the statutory construction argument of Duke Energy in its NSR proceeding. In a unanimous decision, the Court ruled that the Federal EPA was not obligated to define "major modification" in two different CAA provisions in the same way. The Court also found that the Fourth Circuit's interpretation of "major modification" as applying only to projects that increased hourly emission rates amounted to an invalidation of the relevant Federal EPA regulations, which under the CAA can only be challenged in the Court of Appeals within 60 days of the Federal EPA rulemaking. The U.S. Supreme Court did acknowledge, however, that Duke Energy may argue on remand that the Federal EPA has been inconsistent in its interpretations of the CAA and the regulations and may not retroactively change 20 years of accepted practice.

In addition to providing guidance on certain of the merits of the NSR proceedings brought against APCo, CSPCo, I&M and OPCo, the U.S. Supreme Court's issuance of a ruling in the Duke Energy cases has an impact on the timing of the NSR proceedings. The court indicated an intent to issue a decision on liability in the third quarter of 2007. A bench trial on remedy issues, if necessary, is likely to begin in the second half of 2007.

Management is unable to estimate the loss or range of loss related to any contingent liability, if any, the Registrant 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 to be determined by the court. If the Registrant Subsidiaries do not prevail, management believes the Registrant Subsidiaries 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 Registrant 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.

Clean Water Act Regulations

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

Company		Estimated Compliance Investments (in millions)
APCo	$	21
CSPCo		19
I&M		118
OPCo		31

The rule was challenged in the courts by states, advocacy organizations and industry. In January 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. In July

2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. Management cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. Management may seek further review or relief from the schedules included in the permits.

Adoption of New Accounting Pronouncements

FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. The Registrant Subsidiaries adopted FIN 48 effective January 1, 2007. See "FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48"" section of Note 2 and see Note 8 – Income Taxes. The impact of this interpretation was an unfavorable (favorable) adjustment to retained earnings as follows:

Company	(in thousands)
APCo	$ 2,685
CSPCo	3,022
I&M	(327)
OPCo	5,380
PSO	386
SWEPCo	1,642

CONTROLS AND PROCEDURES

During the second quarter of 2007, management, including the principal executive officer and principal financial officer of each of AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2007 these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2007 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 4, *Commitments, Guarantees and Contingencies,* incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2006 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2006 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Our request for rate recovery of additional costs may not be approved in Texas.*(Applies to AEP.)*

TCC has filed a request with the PUCT to increase its transmission and distribution rates. The rate request includes the amounts charged for the delivery of electricity over TCC´s transmission and distribution lines. TCC is seeking approval of an $81 million increase, which includes the expiration of $20 million in billing credits that the PUCT required in approving the merger of CSW into AEP. The credits have been in place since 2000. TCC is requesting a return on equity of 11.25% with a capital structure of approximately 60% debt/40% equity. As part of rebuttal testimony filed in April 2007, TCC reduced its base rate request by $11 million and reduced its return on equity by 0.5%. If the PUCT denies the requested rate recovery, it could adversely impact future results of operations, cash flows and financial condition.

Our request for rate recovery of additional costs may not be approved in Oklahoma.*(Applies to AEP and PSO.)*

PSO filed a request with the OCC in November 2006 seeking approval of a $50 million overall increase in base rates, an annually adjusted rate mechanism to recover the expected significant investment PSO will be making in new facilities, several new and restructured tariffs to allow PSO to begin to reduce the relationship between its revenues and its sales volumes, and to implement some demand side management tariffs. PSO´s planned investments over the next five years include new generation facilities ($1.12 billion), new and refurbished transmission substations and lines ($302 million) and new distribution lines and equipment ($582 million). In April 2007, PSO filed rebuttal testimony regarding various issues raised by the OCC Staff and the intervenors. As part of rebuttal testimony, PSO reduced its base rate request by $2 million. If the OCC denies the requested rate recovery, it could adversely impact future results of operations, cash flows and financial condition.

The amount we charged third parties for using our transmission facilities has been reduced, is subject to refund and may not be completely restored in the future. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Intervenors objected to this decision; therefore the SECA fees we collected ($220 million) are subject to refund. Approximately $19 million of the SECA revenues that we billed were never collected. AEP filed a motion with the FERC to force payment of these SECA billings.

A hearing was held in May 2006 to determine whether any of the SECA revenues should be refunded. In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory, and that new compliance filings and refunds should be made. The ALJ also found that unpaid SECA rates must be paid in the recommended reduced amount. The FERC has not ruled on the matter. If the FERC upholds the decision of the ALJ, it would disallow $90 million of the AEP East companies' remaining $135 million of unsettled gross SECA revenues. We have recorded provisions in the aggregate amount of $37 million related to the potential refund of SECA rates. After completed and in-process settlements of SECA revenues that will consume about $7 million of the reserves for refunds, the AEP East companies will have a remaining reserve balance of $30 million to settle the remaining unsettled gross SECA revenues.

SECA transition rates expired on March 31, 2006 and did not fully compensate AEP East companies for ongoing lost T&O revenues. As a result of rate relief in certain jurisdictions, however, approximately 85% of the ongoing lost T&O revenues are now being recovered from native load customers of AEP East companies in those jurisdictions. The portion attributable to Virginia is being collected subject to refund.

In addition to seeking retail rate recovery from native load customers in the applicable states, AEP and another member of PJM have filed an application with the FERC seeking compensation from other unaffiliated members of PJM for the costs associated with those members' use of the filers' the AEP East companies respective transmission assets. A majority of PJM members have filed in opposition to the proposal. Hearings were held in April 2006. An ALJ recommended a rate design that would result in greater recovery for AEP than the proposal AEP had submitted. The ALJ also recommended, however, that the design be phased-in, which could limit the amount of recovery for AEP. In April 2007, the FERC issued an order reversing the ALJ decision. The FERC ruled that the current PJM rate design is just and reasonable. The FERC further ruled that the cost of new facilities of 500 kV and above would be shared among all PJM participants. Management cannot estimate at this time what affect, if any, this order will have on our future construction of new east transmission facilities, results of operations, cash flows and financial condition.

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP.)*

On June 1, 2001, we purchased HPL from Enron Corp. (Enron). Later that year, Enron and its subsidiaries filed bankruptcy proceedings in the U.S. Bankruptcy Court for the Southern District of New York. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 BCF of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (together with BOA, BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Additionally, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. We purchased 10 BCF of gas from Enron and are currently litigating the rights to the remaining 55 BCF of cushion gas.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. In 2005, we sold HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Risks Relating To State Restructuring

In Ohio, our costs may not be recovered and rates may be reduced. *(Applies to AEP, OPCo and CSPCo.)*

In January 2007, CSPCo and OPCo filed with the PUCO under the 4% provision of their RSPs to increase their annual generation rates for 2007 by $24 million and $8 million, respectively, to recover governmentally-mandated costs. Pursuant to the RSPs, CSPCo and OPCo implemented these proposed increases effective with the first billing cycle in May 2007. These increases are subject to refund until the PUCO issues a final order in the matter. The PUCO staff and intervenors have proposed disallowances. Management is unable to determine the impact of any potential refunds or rider reductions on future results of operations and cash flows.

In March 2007, CSPCo filed an application under the 4% provision of the RSP to adjust the Power Acquisition Rider (PAR) which was authorized in 2005 by the PUCO in connection with CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio and a new purchase power contract to serve the load. The PUCO approved an adjustment to the PAR, which is expected to increase CSPCo's revenues by $22 million and $38 million for 2007 and 2008, respectively.

CSPCo and OPCo are involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the RSPs on December 31, 2008. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, as permitted by the current Ohio restructuring legislation, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009 when the RSP period ends.

Some laws and regulations governing restructuring in Virginia have not yet been interpreted and could harm our business, operating results and financial condition. *(Applies to AEP and APCo.)*

Virginia restructuring legislation was enacted in 1999 providing for retail choice of generation suppliers to be phased in over two years beginning January 1, 2002. It required jurisdictional utilities to unbundle their power supply and energy delivery rates and to file functional separation plans by January 1, 2002. APCo filed its plan with the Virginia SCC and, following Virginia SCC approval of a settlement agreement, now operates in Virginia as a functionally separated electric utility charging unbundled rates for its retail sales of electricity. The settlement agreement addressed functional separation, leaving decisions related to legal separation for later Virginia SCC consideration. While the electric restructuring law in Virginia established the general framework governing the retail electric market, it required the Virginia SCC to issue rules and determinations implementing the law.

In April 2007, Virginia enacted a law providing for cost-based regulation of electric utilities' generation/supply rates. Results of operations and financial condition could be adversely affected when APCo complies with new re-regulation legislation applicable to its generation and supply business.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. In a preliminary ruling filed in February 2007, the Texas state district court (District Court) adjudicating the appeal of the final order in the true-up proceeding found that the PUCT erred in several respects, including the method used to determine stranded costs and the awarding of certain carrying costs. Following the preliminary ruling, the court granted a rehearing of the issue regarding the method to determine stranded costs.

In March 2007, the District Court judge reversed the earlier preliminary decision concluding the sale of assets method to value TCC's nuclear plant was appropriate. It is expected that the parties and intervenors will appeal various portions of the District Court ruling along with other items to the Texas Court of Appeals. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with environmental laws are significant and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to AEP and each Registrant Subsidiary.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from our estimates. All of the costs are incremental to our current investment base and operating cost structure.

If Federal and/or State requirements are imposed on electric utility companies mandating further emission reductions, including limitations on CO_2 emissions, such requirements could make some of our electric generating units uneconomical to maintain or operate. *(Applies to AEP and each Registrant Subsidiary.)*

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA. Future changes in environmental regulations governing these pollutants could make some of our electric generating units uneconomical to maintain or operate. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While mandatory requirements for further emission reductions from our fossil fleet do not appear to be imminent, we continue to monitor regulatory and legislative developments in this area.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations. *(Applies to AEP and each Registrant Subsidiary.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the Federal EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the CAA. The Federal EPA and a number of states alleged that we and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the CAA. The Federal EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded and the court has indicated an intent to issue a decision on liability. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal common law. The trial court dismissed the suits and plaintiffs have appealed the dismissal. While we believe the claims are without merit, the costs associated with reducing CO_2 emissions could harm our business and our results of operations and financial position.

If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended June 30, 2007 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
04/01/07 – 04/30/07	-	$ -	-	$ -
05/01/07 – 05/31/07	2 (a)	73	-	-
06/01/07 – 06/30/07	20 (b)	70	-	-

(a) I&M repurchased 2 shares of its 4.13% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.

(b)

I&M repurchased 20 shares of its 4.13% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.

Item 4. Submission of Matters to a Vote of Security Holders

AEP

The annual meeting of shareholders was held in Shreveport, Louisiana, on April 24, 2007. 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 thirteen 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:

	Number of Shares Voted For	Number of Shares Abstaining
E. R. Brooks	334,998,592	8,663,576
Donald M. Carlton	336,014,182	7,647,986
Ralph D. Crosby, Jr.	335,978,026	7,684,142
John P. DesBarres	335,974,155	7,688,013
Robert W. Fri	332,637,218	11,024,950
Linda A. Goodspeed	336,200,472	7,461,696
William R. Howell	335,739,069	7,923,099
Lester A. Hudson, Jr.	333,116,412	10,545,756
Michael G. Morris	332,139,748	11,522,420
Lionel L. Nowell, III	336,254,000	7,408,168
Richard L. Sandor	332,152,005	11,510,163
Donald G. Smith	333,270,480	10,391,688
Kathryn D. Sullivan	336,273,055	7,389,113

2. Approval of the AEP Senior Officer Incentive Plan. The proposal was approved by a vote of the shareholders as follows:

Votes FOR	317,166,316
Votes AGAINST	20,791,784
Votes ABSTAINED	5,704,068

3. Ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm for 2007. The proposal was approved by a vote of the shareholders as follows:

Votes FOR	335,620,502
Votes AGAINST	4,752,625
Votes ABSTAINED	3,289,041

APCo

The annual meeting of stockholders was held on April 24, 2007 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 13,499,500 votes were cast FOR each of the following nine 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:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Stephen P. Smith
John B. Keane	Susan Tomasky
Holly K. Koeppel	Dennis E. Welch
Michael G. Morris	

I&M

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 24, 2007, the following thirteen persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Marc E. Lewis
Karl G. Boyd	Susanne M. Moorman Rowe
Carl L. English	Michael G. Morris
Allen R. Glassburn	Helen J. Murray
JoAnn M. Grevenow	Robert P. Powers
Patrick C. Hale	Susan Tomasky
Holly K. Koeppel	

OPCo

The annual meeting of shareholders was held on May 1, 2007 at 1 Riverside Plaza, Columbus, Ohio. At the meeting there were 27,952,473 votes cast FOR each of the following nine 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:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Stephen P. Smith
John B. Keane	Susan Tomasky
Holly K. Koeppel	Dennis E. Welch
Michael G. Morris	

SWEPCo

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 11, 2007, the following nine persons were elected directors to hold office for one year or until their successors are elected and qualify:

Nicholas K. Akins	Holly K. Koeppel
Carl L. English	Stephen P. Smith
Thomas M. Hagan	Susan Tomasky
John B. Keane	Dennis E. Welch
Michael G. Morris	

Item 5. **<u>Other Information</u>**

NONE

Item 6. **<u>Exhibits</u>**

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP

31(a) – Certification of AEP Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(c) – Certification of AEP Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(b) – Certification of Registrant Subsidiaries' Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(d) – Certification of Registrant Subsidiaries' Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: August 3, 2007