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, 2009**
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. has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes _X_ No ___

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 has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ___ No ___

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer _X_ *Accelerated filer* ___

Non-accelerated filer ____ *Smaller reporting company* ___

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, non-accelerated filers or smaller reporting companies. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer ____ *Accelerated filer* ___

Non-accelerated filer _X_ *Smaller reporting company* ___

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 and Indiana Michigan Power Company 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 30, 2009
American Electric Power Company, Inc.	476,790,811 ($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, 2009

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
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 electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APB	Accounting Principles Board Opinion.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
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.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo that is consolidated under FIN 46R.
E&R	Environmental compliance and transmission and distribution system reliability.
EaR	Earnings at Risk, a method to quantify risk exposure.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates under FIN 46R.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
ENEC	Expanded Net Energy Cost.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plan.
ETT	Electric Transmission Texas, LLC, a 50% equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in ERCOT.

Term	Meaning
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FSP	FASB Staff Position.
FSP FIN 39-1	FSP FIN 39-1, "Amendment of FASB Interpretation No. 39."
FSP SFAS 107-1 and APB 28-1	FSP SFAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments."
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
JBR	Jet Bubbling Reactor.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP Consolidated's Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PATH	Potomac Appalachian Transmission Highline, LLC and its subsidiaries, a joint venture with Allegheny Energy Inc. formed to own and operate electric transmission facilities in PJM.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.

Term	Meaning
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 and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SEET	Significant Excess Earnings Test.
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."
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants including our ability to restore I&M's Donald C. Cook Nuclear Plant Unit 1 in a timely manner.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) 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 of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- 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, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of the recently passed utility law in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.
- 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.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

EXECUTIVE OVERVIEW

Economic Slowdown

Our residential and commercial KWH sales appear to be relatively stable; nevertheless, some segments of our service territories are experiencing slowdowns. We are currently monitoring the following trends:

- Margins from Off-system Sales - Margins from off-system sales continue to decrease due to reductions in sales volumes and weak market power prices, reflecting reduced overall demand for electricity. We currently forecast that off-system sales volumes will decrease by approximately 34% in 2009 in comparison to 2008.

- Industrial KWH Sales - Industrial KWH sales for the quarter ended June 30, 2009 and the six months ended June 30, 2009 were down 21% and 18%, respectively. Approximately half of the decrease in the first six months of 2009 was due to cutbacks or closures by seven of our large metals producing customers. We also experienced additional significant decreases in KWH sales to customers in the plastics, rubber, auto and paper manufacturing industries. When the economy and export markets recover, we expect to see a return to more normal levels of industrial KWH sales.

- Risk of Loss of Major Customers - We monitor the financial strength and viability of each of our major industrial customers individually. We factor our industrial customer analyses into our operational planning. In July 2009, Ormet, a major industrial customer currently operating at a reduced load of approximately 400 MW, announced that it will substantially curtail operations starting in September 2009.

Regulatory Activity

Our significant 2009 rate proceedings include:

- Arkansas - In February 2009, SWEPCo filed an application with the APSC for an annual base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to recover, in current rates, financing costs related to the construction of the Stall Unit and the Turk Plant. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

- Indiana - In March 2009, the IURC approved the settlement agreement with I&M with modifications that provide for an annual increase in revenues of $42 million, including a $19 million increase in revenue from base rates and $23 million in additional tracker revenues for certain incurred costs, subject to true-up.

- Ohio - In March 2009, and as amended in July 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESP filings. Among other things, the ESP order authorized capped increases to revenues during the three-year ESP period and also authorized a fuel adjustment clause (FAC) which allows CSPCo and OPCo to phase-in and defer actual FAC costs incurred in excess of the caps, that will be trued-up, subject to annual caps. The projected revenue increases for CSPCo and OPCo are listed below:

	Projected Revenue Increases		
	2009	**2010**	**2011**
		(in millions)	
CSPCo	$ 94	$ 109	$ 116
OPCo	103	125	153

  In addition to the revenue increases, net income will be positively affected by the material noncash FAC phase-in deferrals from 2009 through 2011. These deferrals will be collected through a non-bypassable surcharge from 2012 through 2018.

- Virginia - In July 2009, APCo filed a base rate case with the Virginia SCC requesting an increase in the generation and distribution portions of base rates of $169 million annually based on a 13.35% return on common equity which includes a 0.85% return on equity performance incentive increase as permitted by law. The new generation and distribution base rates will be effective, subject to refund, no later than December 2009. In July 2009, APCo filed a motion with the Virginia SCC requesting permission to file, in August 2009, supplemental schedules and testimony reflecting a recent Virginia SCC's order in an unaffiliated utility's base rate case concerning the appropriate capital structure to be used in the determination of the revenue requirement.

  In May 2009, APCo filed an application with the Virginia SCC to increase its fuel adjustment charge by approximately $227 million from July 2009 through August 2010. Due to the significance of the estimated required increase in fuel rates, APCo's application proposed an alternative that would allow APCo to recover applicable costs over the period July 2009 through August 2011. In August 2009, the Virginia SCC issued an order which provides for a $130 million fuel revenue increase.

- West Virginia - In March 2009, APCo and WPCo filed an annual ENEC filing with the WVPSC for an increase of approximately $442 million (later adjusted to $398 million) for incremental fuel, purchased power and environmental compliance project expenses, to become effective July 2009. In March 2009, the WVPSC issued an order suspending the rate increase request until December 2009. APCo and WPCo expect a decision from the WVPSC on the 2009 ENEC filing during the third quarter of 2009.

Turk Plant

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo owns 73% of the Turk Plant and will operate the completed facility.

In November 2007, March 2008 and August 2008, the APSC, LPSC and PUCT, respectively, approved SWEPCo's application to build the Turk Plant. In June 2009, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the Certificate of Environmental Compatibility and Public Need (CECPN) permitting construction of the Turk Plant to serve Arkansas retail customers. Both SWEPCo and the APSC petitioned the Arkansas Supreme Court to review the Arkansas Court of Appeals decision. While the appeals are pending, SWEPCo is continuing construction of the Turk Plant. Should the appeal be unsuccessful, additional proceedings or alternative contractual ownership and operational responsibilities could be required.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. In December 2008, certain parties filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC). The APCEC decision is still pending and not expected until 2010. These same parties have filed a petition with Federal EPA to review the air permit. The Turk Plant cannot be placed in service without an air permit.

For additional details related to the Turk Plant, see the "Turk Plant" section of "Significant Factors."

Capital Markets

Although the financial markets remain volatile at both a global and domestic level, we issued $1.1 billion of long-term debt in the first six months of 2009 and $1.64 billion (net proceeds) of AEP common stock in April 2009. These actions will help to support our investment grade ratings and maintain financial flexibility.

Approximately $1.7 billion of our $17 billion of outstanding long-term debt will mature in 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. We intend to refinance or repay our debt maturities. We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations.

Pension, Nuclear Decommissioning and Other Trust Funds

We have several trust funds with significant investments intended to provide for future payments of pensions, OPEB, nuclear decommissioning and spent nuclear fuel disposal. Although all of our trust funds' investments are diversified and managed in compliance with all laws and regulations, the value of the investments in these trusts declined substantially over the past year due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. The decline in pension asset values will not require us to make a contribution under ERISA in 2009. We currently estimate that we will need to make minimum contributions to our pension trust of $453 million in 2010 and $292 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

Risk Management Contracts

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. Our risk management organization monitors these exposures on a daily basis to limit our economic and financial statement impact on a counterparty basis. At June 30, 2009, our credit exposure net of collateral was approximately $997 million of which approximately 90% is to investment grade counterparties. At June 30, 2009, our exposure to financial institutions was $48 million, which represents 5% of our total credit exposure net of collateral (all investment grade).

Capital Expenditures

In March 2009, due to recent capital market volatility and the economic slowdown, we reduced our budgeted capital expenditures for 2010 from $3.4 billion to $1.8 billion:

	2010 Capital Expenditure Budget (a) (in millions)
New Generation	$ 251 (b)
Environmental	252
Other Generation	431
Transmission	290
Distribution	552
Corporate	70
Total	$ 1,846

(a) Does not include AFUDC.
(b) Includes $212 million and $35 million in budgeted capital expenditures related to the Turk Plant and Stall Unit, respectively.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011. Repair of the property damage and replacement of the turbine rotors and other equipment should be recoverable through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan.

Fuel Inventory

Recent coal consumption and projected consumption for the remainder of 2009 have decreased significantly. As a result of decreased coal consumption and corresponding increases in fuel inventory, we are in discussions with our coal suppliers in an effort to better match deliveries with our current consumption forecast and to minimize the impact on fuel inventory costs.

RESULTS OF OPERATIONS

Segments

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.

AEP River Operations

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss by segment for the three and six months ended June 30, 2009 and 2008.

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)			
Utility Operations	$ 327	$ 264	$ 673	$ 677
AEP River Operations	1	3	12	10
Generation and Marketing	4	26	28	27
All Other (a)	(10)	(12)	(28)	143
Income Before Discontinued Operations and Extraordinary Loss	$ 322	$ 281	$ 685	$ 857

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually liquidate and completely expire in 2011.
- The first quarter 2008 settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP Consolidated

Second Quarter of 2009 Compared to Second Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 increased $41 million compared to 2008 primarily due to an increase in Utility Operations segment earnings of $63 million. The increase in Utility Operations segment net income primarily relates to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower off-system sales margins due to lower sales volumes and lower market prices which reflect weak market demand.

Average basic shares outstanding increased to 472 million in 2009 from 402 million in 2008 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 477 million as of June 30, 2009.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $172 million compared to 2008 primarily due to income of $164 million (net of tax) in 2008 from the cash settlement of a power purchase and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. For our Utility Operations segment, Income Before Discontinued Operations and Extraordinary Loss decreased $4 million primarily due to lower off-system sales margins due to lower sales volumes and lower market prices which reflect weak market demand partially offset by rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories.

Average basic shares outstanding increased to 440 million in 2009 from 401 million in 2008 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 477 million as of June 30, 2009.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
		(in millions)		
Revenues	$ 3,056	$ 3,313	$ 6,323	$ 6,607
Fuel and Purchased Power	996	1,374	2,192	2,587
Gross Margin	2,060	1,939	4,131	4,020
Depreciation and Amortization	388	365	761	720
Other Operating Expenses	993	1,026	1,987	1,967
Operating Income	679	548	1,383	1,333
Other Income, Net	25	48	55	91
Interest Expense	227	218	447	426
Income Tax Expense	150	114	318	321
Income Before Discontinued Operations and Extraordinary Loss	$ 327	$ 264	$ 673	$ 677

Summary of KWH Energy Sales
For Utility Operations
For the Three and Six Months Ended June 30, 2009 and 2008

Energy/Delivery Summary	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions of KWH)			
Energy				
Retail:				
Residential	9,798	9,829	24,166	24,329
Commercial	9,918	9,909	19,312	19,456
Industrial	11,926	15,060	24,052	29,410
Miscellaneous	614	639	1,191	1,248
Total Retail	32,256	35,437	68,721	74,443
Wholesale	7,167	10,996	13,944	22,738
Delivery				
Texas Wires – Energy delivered to customers served by AEP's Texas Wires Companies	6,888	7,132	12,626	12,955
Total KWHs	46,311	53,565	95,291	110,136

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the associated number of customers within each. Cooling degree days and heating degree days in our service territory for the three and six months ended June 30, 2009 and 2008 were as follows:

Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Six Months Ended June 30, 2009 and 2008

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in degree days)			
Weather Summary				
Eastern Region				
Actual – Heating (a)	156	136	2,056	1,966
Normal – Heating (b)	171	175	1,962	1,943
Actual – Cooling (c)	300	277	305	277
Normal – Cooling (b)	286	278	290	281
Western Region (d)				
Actual – Heating (a)	48	40	902	981
Normal – Heating (b)	34	35	939	966
Actual – Cooling (c)	670	677	708	703
Normal – Cooling (b)	658	652	678	672

(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.

Second Quarter of 2009 Compared to Second Quarter of 2008

Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Second Quarter of 2008		$ 264
Changes in Gross Margin:		
Retail Margins	226	
Off-system Sales	(155)	
Transmission Revenues	8	
Other Revenues	42	
Total Change in Gross Margin		121
Total Expenses and Other:		
Other Operation and Maintenance	35	
Gain on Sales of Assets, Net	(2)	
Depreciation and Amortization	(23)	
Interest and Investment Income	(19)	
Carrying Costs Income	(14)	
Allowance for Equity Funds Used During Construction	9	
Interest Expense	(9)	
Equity Earnings of Unconsolidated Subsidiaries	1	
Total Expenses and Other		(22)
Income Tax Expense		(36)
Second Quarter of 2009		$ 327

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

- Retail Margins increased $226 million primarily due to the following:
  - An $83 million increase related to the PUCO's approval of our Ohio ESPs, a $44 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $24 million increase in base rates in Oklahoma and a $20 million net rate increase for I&M.
  - A $40 million increase in fuel margins in Ohio due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the recovery of fuel and related costs during the ESP period. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $62 million increase resulting from reduced sharing of off-system sales margins with retail customers in our eastern service territory due to a decrease in total off-system sales.
  - A $29 million increase related to a coal contract amendment in 2008.

  These increases were partially offset by:
  - A $56 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
  - A $20 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
- Margins from Off-system Sales decreased $155 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading margins.
- Transmission Revenues increased $8 million primarily due to increased rates in the ERCOT and SPP regions.
- Other Revenues increased $42 million primarily due to Cook Plant accidental outage insurance policy proceeds of $45 million. Of these insurance proceeds, $20 million were used to offset fuel costs associated with the Cook Plant Unit 1 shutdown. This increase in revenues was offset by a corresponding decrease in Retail Margins as discussed above. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

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

- Other Operation and Maintenance expenses decreased $35 million primarily due to a $27 million decrease in plant outage and other maintenance expenses and an $8 million decrease related to the 2008 true-up of the 2007 Oklahoma ice storm costs.
- Depreciation and Amortization increased $23 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- Interest and Investment Income decreased $19 million primarily due to the 2008 favorable effect of claims for refund filed with the IRS and the second quarter 2009 write-off of other-than-temporary losses related to equity investments made by EIS.
- Carrying Costs Income decreased $14 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Allowance for Equity Funds Used During Construction increased $9 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009. See "Texas Rate Matters – Texas Restructuring – SPP" section of Note 3.
- Interest Expense increased $9 million primarily due to increased long-term debt and higher interest rates on variable rate, long-term debt.
- Income Tax Expense increased $36 million due to an increase in pretax income.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Six Months Ended June 30, 2008		$ 677
Changes in Gross Margin:		
Retail Margins	286	
Off-system Sales	(291)	
Transmission Revenues	12	
Other Revenues	104	
Total Change in Gross Margin		111
Total Expenses and Other:		
Other Operation and Maintenance	(21)	
Gain on Sales of Assets, Net	1	
Depreciation and Amortization	(41)	
Interest and Investment Income	(29)	
Carrying Costs Income	(22)	
Allowance for Equity Funds Used During Construction	15	
Interest Expense	(21)	
Total Expenses and Other		(118)
Income Tax Expense		3
Six Months Ended June 30, 2009		$ 673

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

- Retail Margins increased $286 million primarily due to the following:
  - A $104 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $96 million increase related to the PUCO's approval of our Ohio ESPs, a $41 million increase in base rates in Oklahoma and a $25 million net rate increase for I&M.
  - A $116 million increase resulting from reduced sharing of off-system sales margins with retail customers in our eastern service territory due to a decrease in total off-system sales.
  - A $47 million increase in fuel margins in Ohio due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the recovery of fuel and related costs during the ESP period. See "Ohio Electric Security Plan Filings" section of Note 3.

  These increases were partially offset by:
  - An $89 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
  - A $40 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
  - A $29 million decrease related to coal contract amendments in 2008.
- Margins from Off-system Sales decreased $291 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading margins.
- Transmission Revenues increased $12 million primarily due to increased rates in the ERCOT and SPP regions.
- Other Revenues increased $104 million primarily due to Cook Plant accidental outage insurance policy proceeds of $99 million. Of these insurance proceeds, $40 million were used to offset fuel costs associated with the Cook Plant Unit 1 shutdown. This increase in revenues was offset by a corresponding decrease in Retail Margins as discussed above. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

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

- Other Operation and Maintenance expenses increased $21 million primarily due to the following:
  - The deferral of $72 million of Oklahoma ice storm costs in 2008 resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $38 million increase related to storm restoration expenses, primarily in our eastern service territory.
  - A $13 million net increase related to an obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of CSPCo's and OPCo's ESPs. See "Ohio Electric Security Plan Filings" section of Note 3.

  These increases were partially offset by:
  - A $54 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $32 million decrease in tree trimming, reliability and other transmission and distribution expenses.
  - The write-off in the first quarter of 2008 of $10 million of unrecoverable pre-construction costs for PSO's cancelled Red Rock Generating Facility.
- Depreciation and Amortization increased $41 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- Interest and Investment Income decreased $29 million primarily due to the 2008 favorable effect of claims for refund filed with the IRS and the second quarter 2009 write-off of other-than-temporary losses related to equity investments made by EIS.
- Carrying Costs Income decreased $22 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Allowance for Equity Funds Used During Construction increased $15 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009. See "Texas Rate Matters – Texas Restructuring – SPP" section of Note 3.
- Interest Expense increased $21 million primarily due to increased long-term debt and higher interest rates on variable rate, long term debt.

AEP River Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $3 million in 2008 to $1 million in 2009 primarily due to reduced import volumes and lower freight rates.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment increased from $10 million in 2008 to $12 million in 2009 primarily due to lower fuel costs and gains on the sale of two older towboats. These increases were partially offset by lower revenues due to reduced import volumes and lower freight rates.

Generation and Marketing

Second Quarter of 2009 Compared to Second Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $26 million in 2008 to $4 million in 2009 primarily due to lower gross margins from marketing activities and decreased margins from the Oklaunion Plant.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased from $27 million in 2008 to $28 million in 2009 primarily due to higher gross margins from marketing activities offset by decreased margins from the Oklaunion Plant.

All Other

Second Quarter of 2009 Compared to Second Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from a loss of $12 million in 2008 to a loss of $10 million in 2009.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $143 million in 2008 to a loss of $28 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a power purchase and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The settlement was recorded as a pretax credit to Asset Impairments and Other Related Charges of $255 million in the accompanying Condensed Consolidated Statements of Income.

AEP System Income Taxes

Income Tax Expense increased $25 million in the second quarter of 2009 compared to the second quarter of 2008 primarily due to an increase in pretax book income.

Income Tax Expense decreased $89 million in the six-month period ended June 30, 2009 compared to the six-month period ended June 30, 2008 primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	June 30, 2009		December 31, 2008	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 16,696	55.5%	$ 15,983	55.6%
Short-term Debt	562	1.8	1,976	6.9
Total Debt	17,258	57.3	17,959	62.5
Preferred Stock of Subsidiaries	61	0.2	61	0.2
AEP Common Equity	12,745	42.4	10,693	37.2
Noncontrolling Interests	18	0.1	17	0.1
Total Debt and Equity Capitalization	$ 30,082	100.0%	$ 28,730	100.0%

Our ratio of debt-to-total capital decreased from 62.5% in 2008 to 57.3% in 2009 primarily due to the issuance of 69 million new common shares and the application of the proceeds to reduce debt.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity. 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 long-term debt, sale-leaseback or leasing agreements or common stock.

Capital Markets

In 2008, the domestic and world economies experienced significant slowdowns. The financial markets remain volatile at both a global and domestic level. This marketplace distress could impact our access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications since we rely on continuing access to capital to fund operations and capital expenditures. We cannot predict the length of time the credit situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates.

We believe we have adequate liquidity under our existing credit facilities. Although we are currently able to access the commercial paper market, the credit markets could constrain our ability to issue commercial paper. At June 30, 2009, we had $3.6 billion in aggregate credit facility commitments to support our operations. These commitments include 28 different banks with only one bank having more than 10% (10.3%) of our total bank commitments.

Through June 30, 2009, we issued $955 million of senior notes with interest rates ranging from 7% to 8.l3% and maturities ranging from 2019 to 2039, $100 million of 6.25% Pollution Control Bonds due 2025 and $34 million of 5.25% Pollution Control Bonds due 2014.

During 2008, we chose to begin eliminating our auction-rate debt position due to market conditions. As of June 30, 2009, $272 million of our auction-rate tax-exempt long-term debt, with rates ranging between 1.122% and 13%, remained outstanding with rates reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. As of June 30, 2009, $218 million of the $272 million of outstanding auction-rate debt relates to JMG. Interest rates on this debt are at the contractual maximum rate of 13%. We were unable to refinance this debt without JMG's consent. We sought approval from the PUCO to terminate the JMG relationship and received the approval in June 2009. In July 2009, we purchased the outstanding equity ownership of JMG for $28 million. We plan to refinance the related outstanding debt as market conditions permit.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At June 30, 2009, our available liquidity was approximately $2.9 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,454 (a)	April 2012
Revolving Credit Facility	627 (a)	April 2011
Total	3,581	
Cash and Cash Equivalents	358	
Total Liquidity Sources	3,939	
Less: Cash Drawn on Credit Facilities	219 (b)	
AEP Commercial Paper Outstanding	316	
Letters of Credit Issued	485	
Net Available Liquidity	$ 2,919	

(a) Contractually terminated Lehman Brothers Bank's commitment amount of $69 million in June 2009.
(b) Repaid in July 2009.

As of June 30, 2009, we had credit facilities totaling $3.6 billion, of which two $1.5 billion credit facilities support our commercial paper program. The two $1.5 billion credit facilities allow for the issuance of up to $750 million as letters of credit under each credit facility. We also have $650 million credit facility which can be utilized for letters of credit or drawings. The $3.6 billion in combined credit facilities were reduced by Lehman Brothers Bank's commitment amount of $69 million following its parent company's bankruptcy.

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. In 2008, we borrowed $2 billion under these credit facilities at a LIBOR rate. In second quarter of 2009, we repaid $1.75 billion of the $2 billion borrowed under the credit facilities with proceeds from our equity offering in April 2009. The maximum amount of commercial paper outstanding during 2009 was $614 million. The weighted-average interest rate for our commercial paper during 2009 was 0.76%.

Sales of Receivables

In July 2009, we renewed and increased our sale of receivables agreement. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables. This agreement will expire in July 2010.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At June 30, 2009, this contractually-defined percentage was 53.3%. Nonperformance of these covenants could result in an event of default under these credit agreements. At June 30, 2009, 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 revolving credit facilities do not permit the lenders to refuse a draw on either facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At June 30, 2009, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 397 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in July 2009. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the AEP Junior Subordinated Debentures issued in March 2008 for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our cash flows or financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

Our credit ratings as of June 30, 2009 were as follows:

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

In 2009, Moody's:

- Placed AEP on negative outlook due to concern about overall credit worthiness, pending rate cases and recessionary pressures.
- Affirmed the Baa2 rating for TCC and downgraded TNC to Baa2. Both companies were also placed on stable outlook.

- Placed OPCo on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries.
- Affirmed the stable rating outlooks for CSPCo, I&M, KPCo and PSO.
- Changed the rating outlook for APCo from negative to stable.
- Downgraded SWEPCo to Baa3 and placed it on stable outlook, reflecting higher business risk associated with the construction of the Turk Plant.

In 2009, Fitch:

- Affirmed its stable rating outlook for I&M, PSO and TNC.
- Changed its rating outlook for TCC from stable to negative due to weak cash flow ratios, challenging regulatory environment and upcoming capital expenditures.
- Changed its rating outlook for SWEPCo from stable to negative due to elevated debt levels to fund Stall Unit and Turk Plant.

If we receive a downgrade in our credit ratings by any of the rating agencies, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 411	$ 178
Net Cash Flows from Operating Activities	857	1,201
Net Cash Flows Used for Investing Activities	(1,478)	(1,645)
Net Cash Flows from Financing Activities	568	484
Net Increase (Decrease) in Cash and Cash Equivalents	(53)	40
Cash and Cash Equivalents at End of Period	$ 358	$ 218

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.

Operating Activities

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)	
Net Income	$ 680	$ 858
Less Discontinued Operations, Net of Tax	-	(1)
Income Before Discontinued Operations	680	857
Depreciation and Amortization	779	736
Other	(602)	(392)
Net Cash Flows from Operating Activities	$ 857	$ 1,201

Net Cash Flows from Operating Activities decreased in 2009 primarily due to a decline in net income and an increase in fuel inventory.

Net Cash Flows from Operating Activities were $857 million in 2009 consisting primarily of Net Income of $680 million and $779 million of noncash depreciation and amortization. Other represents 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. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity as the result of the economic slowdown and an increase in under-recovered fuel primarily due to the deferral of fuel costs in Ohio as a fuel clause was reactivated in 2009.

Net Cash Flows from Operating Activities were $1.2 billion in 2008 consisting primarily of Income Before Discontinued Operations of $857 million and $736 million of noncash depreciation and amortization. Other represents 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. Significant changes in other items include an increase in under-recovered fuel reflecting higher natural gas prices.

Investing Activities

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)	
Construction Expenditures	$ (1,547)	$ (1,608)
Proceeds from Sales of Assets	240	69
Other	(171)	(106)
Net Cash Flows Used for Investing Activities	$ (1,478)	$ (1,645)

Net Cash Flows Used for Investing Activities were $1.5 billion in 2009 and $1.6 billion in 2008 primarily due to Construction Expenditures for our new generation, environmental and distribution investment plan. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners and $92 million for sales of transmission assets in Texas to ETT.

In our normal course of business, we purchase and sell investment securities including variable rate demand notes with cash available for short-term investments and purchase and sell securities within our nuclear trusts and protected cell insurance company. The net amount of these activities is included in Other.

We forecast approximately $2.6 billion of construction expenditures for all of 2009, excluding AFUDC. 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 net income and financing activities.

Financing Activities

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)	
Issuance of Common Stock, Net	$ 1,688	$ 72
Issuance/Retirement of Debt, Net	(711)	777
Dividends Paid on Common Stock	(364)	(333)
Other	(45)	(32)
Net Cash Flows from Financing Activities	$ 568	$ 484

Net Cash Flows from Financing Activities in 2009 were $568 million. Issuance of Common Stock, Net of $1.7 billion included our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $711 million. These retirements included a repayment of $1.75 billion outstanding under our credit facilities primarily from the proceeds of our common stock issuance and issuances of $955 million of senior unsecured notes and $135 million of pollution control bonds. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2008 were $484 million. Our net debt issuances were $777 million. These issuances included a net increase of $1 billion in outstanding senior unsecured notes and the issuance of $315 million of junior subordinated debentures. These net increases in outstanding debt were partially offset by the reacquisition of a net $440 million of pollution control bonds and retirements of $53 million of mortgage notes and $75 million of securitization bonds.

In July 2009, TCC issued $101 million of pollution control bonds due 2029 at 6.3%.

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 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, 2009	December 31, 2008
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 596	$ 650
Rockport Plant Unit 2 Future Minimum Lease Payments	1,996	2,070
Railcars Maximum Potential Loss From Lease Agreement	25	25

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 2008 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2008 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" above and the drawdowns and standby letters of credit discussed in "Liquidity" above.

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 2008 Annual Report. The 2008 Annual Report should be read in conjunction with this report in order to understand significant factors which have not materially changed in status since the issuance of our 2008 Annual Report, but may have a material impact on our future net income, cash flows and financial condition.

Ohio Electric Security Plan Filings

In July 2008, as required by the 2008 amendments to the Ohio restructuring legislation, CSPCo and OPCo filed ESPs with the PUCO to establish standard service offer rates. In March 2009, the PUCO issued an order, which was amended by a rehearing entry in July 2009, that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The capped increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. CSPCo and OPCo implemented rates for the April 2009 billing cycle. In its July 2009 rehearing entry, the PUCO required CSPCo and OPCo to reduce rates implemented in April 2009 by $22 million and $27 million, respectively, on an annualized basis. CSPCo and OPCo are collecting the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

As of June 30, 2009, the recognized revenues and the FAC deferrals were adjusted to reflect the PUCO's July 2009 rehearing entry, which among other things, reversed the prior authorization to recover the cost of CSPCo's recently acquired Waterford and Darby Plants. In July 2009, CSPCo filed an application for rehearing with the PUCO seeking authorization to sell or transfer the Waterford and Darby Plants. The FAC deferrals after adjustment at June 30, 2009 were $34 million and $140 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales.

Consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET) that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings. This is determined by measuring whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, which have comparable business and financial risk. In the March 2009 order, the PUCO determined that off-system sales margins and FAC deferral credits and associated costs should be excluded from the SEET methodology. The July 2009 PUCO rehearing entry deferred those issues to the SEET workshop. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the PUCO must require that the excess amount be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until a SEET filing is made in 2010 and the PUCO issues an order thereon.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP and not to the effective date of tariffs and clarified the tariffs were not retroactive. In the rehearing entry, the PUCO reaffirmed its holding that it had not authorized retroactive rates.

In April 2009, certain intervenors filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases. In May 2009, CSPCo, OPCo and the PUCO filed a motion to dismiss the writ of prohibition. In June 2009, the Ohio Supreme Court dismissed the writ of prohibition.

In June 2009, intervenors filed a motion in the ESP proceeding with the PUCO requesting CSPCo and OPCo to refund deferrals allegedly collected by CSPCo and OPCo which were created by the PUCO's approval of a temporary special arrangement between CSPCo, OPCo and Ormet, a large industrial customer. In addition, the intervenors requested that the PUCO prevent CSPCo and OPCo from collecting these revenues in the future. In June 2009, CSPCo and OPCo filed its response regarding the motion to refund amounts allegedly collected and to prevent future collections. The CSPCo and OPCo response noted that the difference in the amount deferred between the PUCO-determined market price for 2008 and the rate paid by Ormet was not collected, but instead was deferred, with PUCO authorization, as a regulatory asset for future recovery. In the rehearing entry, the PUCO did not order an adjustment to rates based on this issue.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of June 30, 2009, we recorded $54 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursements from NEIL for the cost incurred to date to repair the property damage. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In 2009, I&M recorded $99 million in revenues, including $9 million in revenues that were deferred at December 31, 2008, related to the accidental outage policy. In 2009, I&M applied $40 million of the accidental outage insurance proceeds to reduce customer bills. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 million, respectively. Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. TCC also appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items.

In March 2007, the Texas District Court judge hearing the appeals of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs and remanded this matter to the PUCT for further consideration. This remand could potentially have an adverse effect on TCC's future net income and cash flows if upheld on appeal. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness which could have a favorable effect on TCC's future net income and cash flows.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but two major respects. It reversed the District Court's unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earnings. The favorable commercial unreasonableness judgment entered by the District Court was not reversed. In June 2008, the Texas Court of Appeals denied intervenors' motions for rehearing. In August 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not determined if it will grant review. In January 2009, the Texas Supreme Court requested full briefing of the proceedings which concluded in June 2009.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. TNC appealed its final true-up order, which remains pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in their appeals, it could have a material favorable effect on future net income, cash flows and possibly financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a material adverse effect on future net income, cash flows and possibly financial condition.

New Generation/Purchase Power Agreement

In 2009, AEP is in various stages of construction of the following generation facilities:

Operating Company	Project Name		Location	Total Projected Cost (a) (in millions)	CWIP (b) (in millions)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
AEGCo	Dresden	(c)	Ohio	$ 321	$ 198	Gas	Combined-cycle	580	2013
SWEPCo	Stall		Louisiana	384	322	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(d)	Arkansas	1,628(d)	560(e)	Coal	Ultra-supercritical	600(d)	2012
APCo	Mountaineer	(f)	West Virginia	(f)		Coal	IGCC	629	(f)
CSPCo/OPCo	Great Bend	(f)	Ohio	(f)		Coal	IGCC	629	(f)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(d) SWEPCo owns approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. See "Turk Plant" section below.
(e) Amount represents SWEPCo's CWIP balance only.
(f) Construction of IGCC plants is subject to regulatory approvals. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval for SWEPCo to build the Turk Plant in Arkansas at the existing site by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Certain intervenors appealed the APSC's decision to grant the CECPN to build the Turk Plant to the Arkansas Court of Appeals. In January 2009, the APSC granted additional CECPNs allowing SWEPCo to construct Turk-related transmission facilities. Intervenors also appealed these CECPN orders to the Arkansas Court of Appeals.

In June 2009, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN permitting construction of the Turk Plant to serve Arkansas retail customers. The decision was based upon the Arkansas Court of Appeals' interpretation of the statute that governs the certification process and its conclusion that the APSC did not fully comply with that process. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the generating plant and the proposed transmission facilities' construction and location should all have been considered by the APSC in a single docket instead of separate dockets. Both SWEPCo and the APSC petitioned the Arkansas Supreme Court to review the Arkansas Court of Appeals decision. SWEPCo's petition for review had the effect of staying the Arkansas Court of Appeals decision and, while the appeals are pending, SWEPCo is continuing construction of the Turk Plant. Management believes that the APSC properly interpreted and applied the Arkansas statutes governing the Turk Plant certification process and that SWEPCo's grounds for seeking review are strong.

If the decision of the Court of Appeals is not reversed by the Supreme Court of Arkansas, SWEPCo and the other joint owners of the Turk Plant will evaluate their options. Depending on the time taken by the Arkansas Supreme Court to consider the case and the reasoning of the Arkansas Supreme Court when it acts on SWEPCo's and the APSC's petitions, the construction schedule and/or the cost could be adversely affected. Should the appeal be unsuccessful, additional proceedings or alternative contractual ownership and operational responsibilities could be required.

In March 2008, the LPSC approved the application to construct the Turk Plant. In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions as being unlawful. If the cost cap restrictions are upheld and construction or CO_2 emission costs exceed the restrictions, it could have an adverse effect on net income, cash flows and possibly financial condition. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in Federal District Court by certain Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals. In January 2009, SWEPCo filed a motion to dismiss the appeal, which was granted in March 2009.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. In December 2008, certain parties filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while the appeal of the Turk Plant's permit is heard. In June 2009, hearings on the air permit appeal were held at the APCEC. A decision is still pending and not expected until 2010. These same parties have filed a petition with the Federal EPA to review the air permit. If the air permit were to be remanded or ultimately revoked, construction of the Turk Plant could be suspended or cancelled. The Turk Plant cannot be placed into service without an air permit.

SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers an inadvertent impact on approximately 2.5 acres of wetlands at the Turk Plant construction site prior to the receipt of the permit. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas outside of the proposed Army Corps of Engineers permitted areas of the Turk Plant pending the Army Corps of Engineers review. SWEPCo has entered into a Consent Agreement and Final Order with the Federal EPA to resolve liability for the inadvertent impact and agreed to pay a civil penalty of approximately $29 thousand.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. To date, the report's effect is only advisory, but if legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's ability to complete construction on schedule in 2012 and on budget.

If the Turk Plant cannot be completed and placed in service, SWEPCo would seek approval to recover its prudently incurred capitalized construction costs including any cancellation fees and a return on unrecovered balances through rates in all of its jurisdictions. As of June 30, 2009, and excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $570 million of expenditures (including AFUDC and related transmission costs of $10 million) and has contractual construction commitments for an additional $582 million (including related transmission costs of $7 million). As of June 30, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $136 million (including related transmission cancellation fees of $1 million).

Management believes that SWEPCo's planning, certification and construction of the Turk Plant to date have been in material compliance with all applicable laws and regulations, except for the inadvertent wetlands intrusion discussed above. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if for any reason SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would adversely impact net income, cash flows and possibly financial condition unless the resultant losses can be fully recovered, with a return on unrecovered balances, through rates in all of its jurisdictions.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through June 2009, APCo deferred for future recovery preconstruction IGCC costs of $20 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all pre-construction cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction, it would have an adverse effect on future net income and cash flows.

PSO Purchase Power Agreement

PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, executed a long-term purchase power agreement (PPA) for which an application seeking its approval was filed with the OCC in May 2009. The PPA is for the purchase of up to 520 MW of electric generation from the 795 MW natural gas-fired Green Country Generating Station, located in Jenks, Oklahoma. The agreement is the result of PSO's 2008 Request for Proposals following a December 2007 OCC order that found PSO had a need for new base load generation by 2012. In July 2009, OCC staff, the Independent Evaluator and the Oklahoma Industrial Energy Consumers filed responsive testimony in support of PSO's proposed PPA with Exelon. An order from the OCC is expected before year-end 2009.

The American Recovery and Reinvestment Act of 2009

The American Recovery and Reinvestment Act of 2009 was signed into law by the President in February 2009. It provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions are not expected to have a material impact on net income or financial condition. However, we forecast the bonus depreciation provision could provide a significant favorable cash flow benefit of approximately $300 million in 2009.

Litigation

In the ordinary course of business, we 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 will be, or what the timing of the amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss amount can be estimated. For details on our regulatory proceedings and 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 2008 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 our net income and cash flows.

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 CAA to reduce emissions of SO_2, 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 involved in the development of possible future requirements to reduce CO_2 and other greenhouse gases (GHG) 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 2008 Annual Report.

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.

In 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 sought further review and filed for relief from the schedules included in our permits.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. We cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states.

Potential Regulation of CO_2 and Other GHG Emissions

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act (ACES). ACES is a comprehensive energy and climate change bill that includes a number of provisions that would directly affect our business. ACES contains a combined energy efficiency and renewable electricity standard beginning at 6% in 2012 and increasing to 20% by 2020 of our retail sales. The proposed legislation would also create a carbon capture and sequestration program funded through rates to accelerate the development of this technology and establishes GHG emission standards for new fossil fuel-fired electric generating plants. ACES creates an economy-wide cap and trade program for large sources of GHG emissions that would reduce emissions by 17% in 2020 and just over 80% by 2050 from 2005 levels. A portion of the allowances under the cap and trade program would be allocated to retail electric and gas utilities, certain energy-intensive industries, small refiners and state governments. Some allowances would be auctioned. Bonus allowances would be available to encourage energy efficiency, renewable energy and carbon sequestration projects. Consideration of climate legislation has now moved to the Senate. Until legislation is final, we are unable to predict its impact on net income, cash flows and financial condition.

In April 2009, the Federal EPA issued a proposed endangerment finding under the CAA regarding GHG emissions from motor vehicles. The proposed endangerment finding is subject to public comment. This finding could lead to regulation of CO_2 and other gases under existing laws. Congress continues to discuss new legislation related to the control of these emissions. Some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including us. Because of these adverse consequences, management believes that these more extreme policies will not ultimately be adopted. Even if reasonable CO_2 and other GHG emission standards are imposed, they will still require us to make material expenditures. Management believes that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers, and should be recoverable from customers as costs of doing business including capital investments with a return on investment.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2008 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

The FASB issued SFAS 141R "Business Combinations" improving financial reporting about business combinations and their effects and FSP SFAS 141(R)-1. SFAS 141R can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments. We adopted SFAS 141R, including the FSP, effective January 1, 2009. We will apply it to any future business combinations.

The FASB issued SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. We adopted SFAS 160 effective January 1, 2009 and retrospectively applied the standard to prior periods. See Note 2.

The FASB issued SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard increased our disclosure requirements related to derivative instruments and hedging activities. We adopted SFAS 161 effective January 1, 2009.

In May 2009, the FASB issued SFAS 165 "Subsequent Events" (SFAS 165), incorporating guidance on subsequent events into authoritative accounting literature and clarifying the time following the balance sheet date which management reviewed for events and transactions that may require disclosure in the financial statements. We adopted this standard effective second quarter of 2009. The standard increased our disclosure by requiring disclosure of the date through which subsequent events have been reviewed. The standard did not change our procedures for reviewing subsequent events.

The FASB ratified EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5), a consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. We adopted EITF 08-5 effective January 1, 2009. With the adoption of FSP SFAS 107-1 and APB 28-1, it is applied to the fair value of long-term debt. The application of this standard had an immaterial effect on the fair value of debt outstanding.

The FASB ratified EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. We prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements.

We adopted FSP EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (EITF 03-6-1), effective January 1, 2009. The rule addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method. The adoption of this standard had an immaterial impact on our financial statements.

The FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments. We adopted the standard effective second quarter of 2009. This standard increased the disclosure requirements related to financial instruments.

The FASB issued FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments", amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements. We adopted the standard effective second quarter of 2009 with no impact on our financial statements and increased disclosure requirements related to financial instruments.

The FASB issued FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets”, amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. We adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

The FASB issued SFAS 157-2 “Effective Date of FASB Statement No. 157” (SFAS 157-2), which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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. We adopted SFAS 157-2 effective January 1, 2009. We will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. We did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in 2009.

The FASB issued FSP SFAS 157-4 “Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly” (FSP SFAS 157-4), providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods. We adopted the standard effective second quarter of 2009. This standard had no impact on our financial statements but increased our disclosure requirements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. 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.

Our Generation and Marketing segment, operating primarily within ERCOT, transacts in wholesale energy trading and marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. 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 financial derivatives, which will gradually settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances 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 oversight 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 Executive Vice President - Generation, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. 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.

The Committee of Chief Risk Officers (CCRO) adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. 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 balance sheet as of June 30, 2009 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet June 30, 2009 (in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	Cash Flow Hedge Contracts	Collateral Deposits	Total
Current Assets	$ 257	$ 33	$ 7	$ 297	$ 56	$ (18)	$ 335
Noncurrent Assets	182	205	6	393	4	(17)	380
Total Assets	439	238	13	690	60	(35)	715
Current Liabilities	154	25	12	191	23	(56)	158
Noncurrent Liabilities	104	73	6	183	5	(50)	138
Total Liabilities	258	98	18	374	28	(106)	296
Total MTM Derivative Contract Net Assets (Liabilities)	$ 181	$ 140	$ (5)	$ 316	$ 32	$ 71	$ 419

MTM Risk Management Contract Net Assets (Liabilities) Six Months Ended June 30, 2009 (in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2008	$ 175	$ 104	$ (7)	$ 272
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(60)	(6)	2	(64)
Fair Value of New Contracts at Inception When Entered During the Period (a)	13	54	-	67
Net Option Premiums Paid (Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	-	-
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	11	(12)	-	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	42	-	-	42
Total MTM Risk Management Contract Net Assets (Liabilities) at June 30, 2009	$ 181	$ 140	$ (5)	316
Cash Flow Hedge Contracts				32
Collateral Deposits				71
Ending Net Risk Management Assets at June 30, 2009				$ 419

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

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

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

The following table presents 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) June 30, 2009 (in millions)

	Remainder 2009	2010	2011	2012	2013	After 2013 (f)	Total
Utility Operations							
Level 1 (a)	$ (3)	$ -	$ -	$ -	$ -	$ -	$ (3)
Level 2 (b)	46	45	17	-	3	1	112
Level 3 (c)	13	18	6	3	-	-	40
Total	56	63	23	3	3	1	149
Generation and Marketing							
Level 1 (a)	(5)	1	-	-	-	-	(4)
Level 2 (b)	4	15	18	16	20	44	117
Level 3 (c)	-	1	1	2	2	21	27
Total	(1)	17	19	18	22	65	140
All Other							
Level 1 (a)	-	(1)	-	-	-	-	(1)
Level 2 (b)	(2)	(4)	2	-	-	-	(4)
Level 3 (c)	-	-	-	-	-	-	-
Total	(2)	(5)	2	-	-	-	(5)
Total							
Level 1 (a)	(8)	-	-	-	-	-	(8)
Level 2 (b)	48	56	37	16	23	45	225
Level 3 (c) (d)	13	19	7	5	2	21	67
Total	53	75	44	21	25	66	284
Dedesignated Risk Management Contracts (e)	7	14	6	5	-	-	32
Total MTM Risk Management Contract Net Assets	$ 60	$ 89	$ 50	$ 26	$ 25	$ 66	$ 316

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1 and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.
(d) A significant portion of the total volumetric position within the consolidated Level 3 balance has been economically hedged.
(e) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized within Utility Operations Revenues over the remaining life of the contracts.
(f) There is mark-to-market value of $66 million in individual periods beyond 2013. $46 million of this mark-to-market value is in periods 2014-2018, $15 million is in periods 2019-2023 and $5 million is in periods 2024-2028.

Credit Risk

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At June 30, 2009, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.2%, 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, 2009, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 656	$ 56	$ 600	1	$ 121
Split Rating	14	-	14	3	13
Noninvestment Grade	14	2	12	1	11
No External Ratings:					
Internal Investment Grade	304	3	301	3	245
Internal Noninvestment Grade	81	11	70	2	54
Total as of June 30, 2009	$ 1,069	$ 72	$ 997	10	$ 444
Total as of December 31, 2008	$ 793	$ 29	$ 764	9	$ 284

See Note 8 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

VaR Associated with Risk Management Contracts

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, 2009 a near term typical change in commodity prices is not expected to have a material effect on our net income, 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, 2009 (in millions)				Twelve Months Ended December 31, 2008 (in millions)			
End	High	Average	Low	End	High	Average	Low
$1	$2	$1	$-	$-	$3	$1	$-

We back-test our VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Our back-testing results show that our actual performance exceeded VaR far fewer than once every 20 trading days. As a result, we believe our VaR calculation is conservative.

As our VaR calculation captures recent price moves, we also perform regular stress testing of the portfolio to understand our exposure to extreme price moves. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. We then research the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of June 30, 2009, the estimated EaR on our debt portfolio for the following twelve months was $28 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended		Six Months Ended	
REVENUES	**2009**	**2008**	**2009**	**2008**
Utility Operations	$ 3,035	$ 3,200	$ 6,302	$ 6,210
Other Revenues	167	346	358	803
TOTAL REVENUES	3,202	3,546	6,660	7,013
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	764	1,053	1,693	2,033
Purchased Electricity for Resale	258	366	553	629
Other Operation and Maintenance	911	982	1,825	1,860
Gain on Sales of Assets, Net	(2)	(5)	(11)	(8)
Asset Impairments and Other Related Charges	-	-	-	(255)
Depreciation and Amortization	397	373	779	736
Taxes Other Than Income Taxes	192	191	389	389
TOTAL EXPENSES	2,520	2,960	5,228	5,384
OPERATING INCOME	682	586	1,432	1,629
Other Income (Expense):				
Interest and Investment Income (Loss)	(5)	15	-	31
Carrying Costs Income	12	26	21	43
Allowance for Equity Funds Used During Construction	20	11	36	21
Interest Expense	(240)	(234)	(478)	(453)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	469	404	1,011	1,271
Income Tax Expense	148	123	327	416
Equity Earnings of Unconsolidated Subsidiaries	1	-	1	2
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	322	281	685	857
DISCONTINUED OPERATIONS, NET OF TAX	-	1	-	1
INCOME BEFORE EXTRAORDINARY LOSS	322	282	685	858
EXTRAORDINARY LOSS, NET OF TAX	(5)	-	(5)	-
NET INCOME	317	282	680	858
Less: Net Income Attributable to Noncontrolling Interests	1	1	3	3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	316	281	677	855
Less: Preferred Stock Dividend Requirements of Subsidiaries	-	-	1	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 316	$ 281	$ 676	$ 854
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	472,220,041	401,513,958	439,703,968	401,155,975
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Discontinued Operations and Extraordinary Loss	$ 0.68	$ 0.70	$ 1.55	$ 2.13
Discontinued Operations, Net of Tax	-	-	-	-
Income Before Extraordinary Loss	0.68	0.70	1.55	2.13
Extraordinary Loss, Net of Tax	(0.01)	-	(0.01)	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 0.67	$ 0.70	$ 1.54	$ 2.13
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	472,222,817	402,785,942	439,983,030	402,429,019
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Discontinued Operations and Extraordinary Loss	$ 0.68	$ 0.70	$ 1.55	$ 2.12
Discontinued Operations, Net of Tax	-	-	-	-
Income Before Extraordinary Loss	0.68	0.70	1.55	2.12
Extraordinary Loss, Net of Tax	(0.01)	-	(0.01)	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 0.67	$ 0.70	$ 1.54	$ 2.12
CASH DIVIDENDS PAID PER SHARE	$ 0.41	$ 0.41	$ 0.82	$ 0.82

See Condensed Notes to Condensed consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in millions)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 358	$ 411
Other Temporary Investments	289	327
Accounts Receivable:		
Customers	570	569
Accrued Unbilled Revenues	437	449
Miscellaneous	73	90
Allowance for Uncollectible Accounts	(43)	(42)
Total Accounts Receivable	1,037	1,066
Fuel	911	634
Materials and Supplies	575	539
Risk Management Assets	335	256
Regulatory Asset for Under-Recovered Fuel Costs	352	284
Margin Deposits	135	86
Prepayments and Other Current Assets	232	172
TOTAL CURRENT ASSETS	4,224	3,775
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	22,480	21,242
Transmission	8,084	7,938
Distribution	13,179	12,816
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,810	3,741
Construction Work in Progress	3,145	3,973
Total Property, Plant and Equipment	50,698	49,710
Accumulated Depreciation and Amortization	17,139	16,723
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	33,559	32,987
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,979	3,783
Securitized Transition Assets	1,983	2,040
Spent Nuclear Fuel and Decommissioning Trusts	1,268	1,260
Goodwill	76	76
Long-term Risk Management Assets	380	355
Deferred Charges and Other Noncurrent Assets	869	879
TOTAL OTHER NONCURRENT ASSETS	8,555	8,393
TOTAL ASSETS	$ 46,338	$ 45,155

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,096	$ 1,297
Short-term Debt	562	1,976
Long-term Debt Due Within One Year	1,346	447
Risk Management Liabilities	158	134
Customer Deposits	271	254
Accrued Taxes	553	634
Accrued Interest	273	270
Regulatory Liability for Over-Recovered Fuel Costs	130	66
Other Current Liabilities	1,004	1,219
TOTAL CURRENT LIABILITIES	5,393	6,297
NONCURRENT LIABILITIES		
Long-term Debt	15,350	15,536
Long-term Risk Management Liabilities	138	170
Deferred Income Taxes	5,417	5,128
Regulatory Liabilities and Deferred Investment Tax Credits	2,746	2,789
Asset Retirement Obligations	1,181	1,154
Employee Benefits and Pension Obligations	2,169	2,184
Deferred Credits and Other Noncurrent Liabilities	1,120	1,126
TOTAL NONCURRENT LIABILITIES	28,121	28,087
TOTAL LIABILITIES	33,514	34,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock Par Value $6.50:		
Shares Authorized: 2009 600,000,000; 2008 600,000,000		
Shares Issued: 2009 497,033,402; 2008 426,321,248		
(20,249,992 shares were held in treasury at June 30, 2009 and December 31, 2008)	3,231	2,771
Paid-in Capital	5,755	4,527
Retained Earnings	4,160	3,847
Accumulated Other Comprehensive Income (Loss)	(401)	(452)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	12,745	10,693
Noncontrolling Interests	18	17
TOTAL EQUITY	12,763	10,710
TOTAL LIABILITIES AND EQUITY	$ 46,338	$ 45,155

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, 2009 and 2008
(in millions)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 680	$ 858
Less: Discontinued Operations, Net of Tax	-	(1)
Income Before Discontinued Operations	680	857
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	779	736
Deferred Income Taxes	360	316
Extraordinary Loss, Net of Tax	5	-
Carrying Costs Income	(21)	(43)
Allowance for Equity Funds Used During Construction	(36)	(21)
Mark-to-Market of Risk Management Contracts	(83)	66
Amortization of Nuclear Fuel	25	45
Deferred Property Taxes	38	36
Fuel Over/Under-Recovery, Net	(246)	(245)
Gain on Sales of Assets, Net	(11)	(8)
Change in Other Noncurrent Assets	-	(195)
Change in Other Noncurrent Liabilities	84	(90)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	29	(123)
Fuel, Materials and Supplies	(313)	(82)
Margin Deposits	(49)	(16)
Accounts Payable	18	188
Customer Deposits	17	18
Accrued Taxes, Net	(110)	(61)
Accrued Interest	3	16
Other Current Assets	(25)	(13)
Other Current Liabilities	(287)	(180)
Net Cash Flows from Operating Activities	857	1,201
INVESTING ACTIVITIES		
Construction Expenditures	(1,547)	(1,608)
Change in Other Temporary Investments, Net	43	48
Purchases of Investment Securities	(443)	(635)
Sales of Investment Securities	411	666
Acquisitions of Nuclear Fuel	(152)	(99)
Acquisitions of Assets	(11)	(81)
Proceeds from Sales of Assets	240	69
Other Investing Activities	(19)	(5)
Net Cash Flows Used for Investing Activities	(1,478)	(1,645)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	1,688	72
Change in Short-term Debt, Net	(1,414)	45
Issuance of Long-term Debt	1,075	2,204
Retirement of Long-term Debt	(372)	(1,472)
Principal Payments for Capital Lease Obligations	(42)	(48)
Dividends Paid on Common Stock	(364)	(333)
Dividends Paid on Cumulative Preferred Stock	(1)	(1)
Other Financing Activities	(2)	17
Net Cash Flows from Financing Activities	568	484
Net Increase (Decrease) in Cash and Cash Equivalents	(53)	40
Cash and Cash Equivalents at Beginning of Period	411	178
Cash and Cash Equivalents at End of Period	$ 358	$ 218
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 495	$ 412
Net Cash Paid for Income Taxes	27	131
Noncash Acquisitions Under Capital Leases	17	35
Noncash Acquisition of Land/Mineral Rights	-	42
Construction Expenditures Included in Accounts Payable at June 30,	270	328

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2009 and 2008
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other Comprehensive Income (Loss)		
	Shares	Amount	Paid-in Capital	Retained Earnings		Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 18	$ 10,097
EITF 06-10 Adoption, Net of Tax of $6				(10)			(10)
SFAS 157 Adoption, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	2	11	61				72
Common Stock Dividends				(330)		(3)	(333)
Preferred Stock Dividends				(1)			(1)
Other Changes in Equity			2			1	3
SUBTOTAL – EQUITY							9,827
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $19					(34)		(34)
Securities Available for Sale, Net of Tax of $4					(7)		(7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					6		6
NET INCOME				855		3	858
TOTAL COMPREHENSIVE INCOME							823
TOTAL EQUITY – JUNE 30, 2008	424	$ 2,754	$ 4,415	$ 3,651	$ (189)	$ 19	$ 10,650
TOTAL EQUITY – DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	71	460	1,278				1,738
Common Stock Dividends				(363)		(3)	(366)
Preferred Stock Dividends				(1)			(1)
Other Changes in Equity			(50)			1	(49)
SUBTOTAL – EQUITY							12,032
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $9					17		17
Securities Available for Sale, Net of Tax of $5					9		9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $14					25		25
NET INCOME				677		3	680
TOTAL COMPREHENSIVE INCOME							731
TOTAL EQUITY – JUNE 30, 2009	497	$ 3,231	$ 5,755	$ 4,160	$ (401)	$ 18	$ 12,763

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed consolidated financial statements and footnotes were prepared in accordance with 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 of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2009 are not necessarily indicative of results that may be expected for the year ending December 31, 2009. We reviewed subsequent events through our Form 10-Q issuance date of August 4, 2009. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2008 consolidated financial statements and notes thereto, which are included in our Annual Report on Form 10-K for the year ended December 31, 2008 as filed with the SEC on February 27, 2009.

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,			
	2009		2008	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 316		$ 281	
Weighted Average Number of Basic Shares Outstanding	472.2	$ 0.67	401.5	$ 0.70
Weighted Average Dilutive Effect of:				
Performance Share Units	-	-	0.9	-
Stock Options	-	-	0.2	-
Restricted Stock Units	-	-	0.1	-
Restricted Shares	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	472.2	$ 0.67	402.8	$ 0.70

	Six Months Ended June 30,			
	2009		2008	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 676		$ 854	
Weighted Average Number of Basic Shares Outstanding	439.7	$ 1.54	401.2	$ 2.13
Weighted Average Dilutive Effect of:				
Performance Share Units	0.3	-	0.8	(0.01)
Stock Options	-	-	0.2	-
Restricted Stock Units	-	-	0.1	-
Restricted Shares	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	440.0	$ 1.54	402.4	$ 2.12

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

Options to purchase 1,123,869 and 146,900 shares of common stock were outstanding at June 30, 2009 and 2008, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the quarter-end market price of the common shares and, therefore, the effect would be antidilutive.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments have been consistently applied and that there are no other reasonable judgments or assumptions that would have resulted in a different conclusion.

We are the primary beneficiary of Sabine, DHLC, JMG and a protected cell of EIS. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series). In addition, we have not provided material financial or other support to any VIE that was not previously contractually required.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. Based on these facts, management has concluded SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended June 30, 2009 and 2008 were $25 million and $28 million, respectively, and for the six months ended June 30, 2009 and 2008 were $61 million and $48 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Condensed Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHLC. SWEPCo's total billings from DHLC for both the three months ended June 30, 2009 and 2008 were $8 million and for the six months ended June 30, 2009 and 2008 were $18 million and $20 million, respectively. See the tables below for the classification of DHLC assets and liabilities on our Condensed Consolidated Balance Sheets.

OPCo has a lease agreement with JMG to finance OPCo's Flue Gas Desulfurization (FGD) system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments are the only form of repayment associated with JMG's debt obligations even though OPCo does not guarantee JMG's debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. As of June 30, 2009, OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded OPCo is the primary beneficiary and is required to consolidate JMG. OPCo's total billings from JMG for the three months ended June 30, 2009 and 2008 were $31 million and $13 million, respectively, and for the six months ended June 30, 2009 and 2008 were $49 million and $26 million, respectively. See the tables below for the classification of JMG's assets and liabilities on our Condensed Consolidated Balance Sheets.

In April 2009, OPCo paid JMG $58 million which was used to retire certain long-term debt of JMG. While this payment was not contractually required, OPCo made this payment in anticipation of purchasing the outstanding equity of JMG.

In July 2009, OPCo purchased all of the outstanding equity ownership of JMG for $28 million. Our intent is to dissolve JMG. The assets and liabilities of JMG will remain incorporated with OPCo's business.

EIS is a captive insurance company with multiple protected cells in which our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP system is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on the structure of the protected cell, management has concluded that we are the primary beneficiary and that we are required to consolidate the protected cell. Our insurance premium payments to EIS for the three months ended June 30, 2009 and 2008 were $132 thousand and $42 thousand, respectively, and for the six months ended June 30, 2009 and 2008 were $17 million in both periods. See the tables below for the classification of EIS's assets and liabilities on our Condensed Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
June 30, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	EIS
ASSETS				
Current Assets	$ 37	$ 15	$ 16	$ 118
Net Property, Plant and Equipment	125	30	413	-
Other Noncurrent Assets	30	12	1	2
Total Assets	$ 192	$ 57	$ 430	$ 120
LIABILITIES AND EQUITY				
Current Liabilities	$ 40	$ 12	$ 150	$ 33
Noncurrent Liabilities	152	42	262	76
Equity	-	3	18	11
Total Liabilities and Equity	$ 192	$ 57	$ 430	$ 120

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2008
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	EIS
ASSETS				
Current Assets	$ 33	$ 22	$ 11	$ 107
Net Property, Plant and Equipment	117	33	423	-
Other Noncurrent Assets	24	11	1	2
Total Assets	$ 174	$ 66	$ 435	$ 109
LIABILITIES AND EQUITY				
Current Liabilities	$ 32	$ 18	$ 161	$ 30
Noncurrent Liabilities	142	44	257	60
Equity	-	4	17	19
Total Liabilities and Equity	$ 174	$ 66	$ 435	$ 109

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and us and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. The other series are not considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. Currently the entity has no debt financing. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	June 30, 2009		December 31, 2008	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 5	$ 5	$ 4	$ 4
Retained Earnings	2	2	2	2
Total Investment in PATH-WV	$ 7	$ 7	$ 6	$ 6

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity 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.

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. We then purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our Condensed Consolidated Statements of Income. However, in 2009, there were times when we were a purchaser of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale 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 exchanges.

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on our Condensed Consolidated Statements of Income.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, we revised book depreciation rates for CSPCo and OPCo generating plants consistent with a recently completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. In comparing 2009 and 2008, the change in depreciation rates resulted in a net increase (decrease) in deprecation expense of:

	Total Depreciation Expense Variance	
	Three Months Ended June 30, 2009/2008	Six Months Ended June 30, 2009/2008
	(in millions)	
CSPCo	$ (5)	$ (9)
OPCo	17	34

The net change in depreciation rates resulted in decreases to our net-of-tax, basic earnings per share of $0.02 and $0.04 for the three months ended June 30, 2009 and six months ended June 30, 2009, respectively.

Supplementary Information

Related Party Transactions	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)			
AEP Consolidated Revenues – Utility Operations:				
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% owned) (a)	$ -	$ (13)	$ -	$ (25)
AEP Consolidated Revenues – Other:				
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	7	5	16	14
AEP Consolidated Expenses – Purchased Energy for Resale:				
Ohio Valley Electric Corporation (43.47% Owned)	72	61	142	124

(a) In 2006, the AEP Power Pool began purchasing power from OVEC as part of risk management activities. The agreement expired in May 2008 and subsequently ended in December 2008.

Shown below are income statement amounts attributable to AEP common shareholders:

Amounts Attributable To AEP Common Shareholders	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)			
Income Before Discontinued Operations and Extraordinary Loss	$ 321	$ 280	$ 681	$ 853
Discontinued Operations, Net of Tax	-	1	-	1
Extraordinary Loss, Net of Tax	(5)	-	(5)	-
Net Income	$ 316	$ 281	$ 676	$ 854

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements issued or implemented in 2009 and standards issued but not implemented that we have determined relate to our operations.

Pronouncements Adopted During 2009

The following standards were effective during the first six months of 2009. Consequently, the financial statements and footnotes reflect their impact.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

We adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. We had no business combinations in 2009. We will apply it to any future business combinations.

SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

We adopted SFAS 160 effective January 1, 2009 and retrospectively applied the standard to prior periods. The retrospective application of this standard:

- Reclassifies Minority Interest Expense of $1 million and $2 million and Interest Expense of $0 million and $1 million for the three and six months ended June 30, 2008, respectively, as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to AEP Common Shareholders in our Condensed Consolidated Statements of Income.
- Repositions Preferred Stock Dividend Requirements of Subsidiaries of $0 million and $1 million for the three and six months ended June 30, 2008, respectively, below Net Income in the presentation of Earnings Attributable to AEP Common Shareholders in our Condensed Consolidated Statements of Income.
- Reclassifies minority interest of $17 million as of December 31, 2008 previously included in Deferred Credits and Other Noncurrent Liabilities and Total Liabilities as Noncontrolling Interest in Total Equity on our Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interest in the Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $3 million for the six months ended June 30, 2008 from Operating Activities to Financing Activities in our Condensed Consolidated Statements of Cash Flows.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

We adopted SFAS 161 effective January 1, 2009. This standard increased our disclosures related to derivative instruments and hedging activities. See Note 8.

SFAS 165 "Subsequent Events" (SFAS 165)

In May 2009, the FASB issued SFAS 165 incorporating guidance on subsequent events into authoritative accounting literature and clarifying the time following the balance sheet date which management reviewed for events and transactions that may require disclosure in the financial statements.

We adopted this standard effective second quarter of 2009. The standard increased our disclosure by requiring disclosure of the date through which subsequent events have been reviewed. The standard did not change our procedures for reviewing subsequent events.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

We adopted EITF 08-5 effective January 1, 2009. With the adoption of FSP SFAS 107-1 and APB 28-1, it is applied to the fair value of long-term debt. The application of this standard had an immaterial effect on the fair value of debt outstanding.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

We adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements. It was applied prospectively.

FSP EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (EITF 03-6-1)

In June 2008, the FASB addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method described in SFAS 128 "Earnings per Share."

We adopted EITF 03-6-1 effective January 1, 2009. The adoption of this standard had an immaterial impact on our financial statements.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

We adopted the standard effective second quarter of 2009. This standard increased the disclosure requirements related to financial instruments. See "Fair Value Measurements of Long-term Debt" section of Note 9.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

We adopted the standard effective second quarter of 2009 with no impact on our financial statements and increased disclosure requirements related to financial instruments. See "Fair Value Measurements of Other Temporary Investments" and "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" sections of Note 9.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

We adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued SFAS 157-2 which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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.

We adopted SFAS 157-2 effective January 1, 2009. We will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analyses related to long-lived assets, equity investments, goodwill and intangibles. We did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first six months of 2009.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

We adopted the standard effective second quarter of 2009. This standard had no impact on our financial statements but increased our disclosure requirements. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 9.

<u>Pronouncements Effective in the Future</u>

The following standards will be effective in the future and their impacts will be disclosed at that time.

SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)

In June 2009, the FASB issued SFAS 166 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

SFAS 166 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Although we have not completed our analysis, we do not expect this standard to have a material impact on our financial statements. We will adopt SFAS 166 effective January 1, 2010.

SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167)

In June 2009, the FASB issued SFAS 167 amending the analysis an entity must perform to determine if it has a controlling interest in a variable interest entity (VIE). This new guidance provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
- The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The standard also requires separate presentation on the face of the statement of financial position for assets which can only be used to settle obligations of a consolidated VIE and liabilities for which creditors do not have recourse to the general credit of the primary beneficiary.

SFAS 167 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. We continue to review the impact of the changes in the consolidation guidance on our financial statements. This standard will increase our disclosure requirements related to transactions with VIEs and change the presentation of consolidated VIE's assets and liabilities on our Condensed Consolidated Balance Sheets. We will adopt SFAS 167 effective January 1, 2010.

SFAS 168 "The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles" (SFAS 168)

In June 2009, the FASB issued SFAS 168 establishing the FASB Accounting Standards Codification™ as the authoritative source of accounting principles for preparation of financial statements and reporting in conformity with GAAP by nongovernmental entities.

This standard is effective for interim and annual reporting periods ending after September 15, 2009. It requires an update of all references to authoritative accounting literature. We will adopt SFAS 168 effective third quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policies including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, earnings per share calculations, leases, insurance, hedge accounting, consolidation policy, discontinued operations and income tax. 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 net income and financial position.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo returned to cost-based regulation and re-applied SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of SFAS 71 regulatory accounting resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. RATE MATTERS

As discussed in the 2008 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2008 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2009 and updates the 2008 Annual Report.

Ohio Rate Matters

Ohio Electric Security Plan Filings

In July 2008, as required by the 2008 amendments to the Ohio restructuring legislation, CSPCo and OPCo filed ESPs with the PUCO to establish standard service offer rates. In March 2009, the PUCO issued an order, which was amended by a rehearing entry in July 2009, that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The capped increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. CSPCo and OPCo implemented rates for the April 2009 billing cycle. In its July 2009 rehearing entry, the PUCO required CSPCo and OPCo to reduce rates implemented in April 2009 by $22 million and $27 million, respectively, on an annualized basis. CSPCo and OPCo are collecting the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

As of June 30, 2009, the recognized revenues and the FAC deferrals were adjusted to reflect the PUCO's July 2009 rehearing entry, which among other things, reversed the prior authorization to recover the cost of CSPCo's recently acquired Waterford and Darby Plants. In July 2009, CSPCo filed an application for rehearing with the PUCO seeking authorization to sell or transfer the Waterford and Darby Plants. The FAC deferrals after adjustments at June 30, 2009 were $34 million and $140 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales.

The PUCO also addressed several additional matters which are described below:

- CSPCo should attempt to mitigate the costs of its gridSMART advanced metering proposal that will affect portions of its service territory by seeking matching funds under the American Recovery and Reinvestment Act of 2009. CSPCo plans to file for these matching federal funds during the third quarter of 2009. As a result, a rider was established to recover 50% or $32 million of the projected $64 million revenue requirement related to gridSMART.

- CSPCo and OPCo can recover their incremental carrying costs related to environmental investments made from 2001 through 2008 that are not reflected in existing rates. Future recovery during the ESP period of incremental carrying charges on environmental expenditures incurred beginning in 2009 may be requested in annual filings.

- CSPCo's and OPCo's Provider of Last Resort revenues were increased by $97 million and $55 million, respectively, to compensate for the risk of customers changing electric suppliers during the ESP period.

- CSPCo and OPCo must fund a combined minimum of $15 million in costs over the ESP period for low-income, at-risk customer programs. In March 2009, this funding obligation was recognized as a liability and charged to Other Operation and Maintenance expense. At June 30, 2009, CSPCo's and OPCo's liability balance was $6.5 million each.

Consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET) that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings. This is determined by measuring whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, which have comparable business and financial risk. In the March 2009 order, the PUCO determined that off-system sales margins and FAC deferral credits and associated costs should be excluded from the SEET methodology. The July 2009 PUCO rehearing entry deferred those issues to the SEET workshop. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the PUCO must require that the excess amount be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until a SEET filing is made in 2010 and the PUCO issues an order thereon.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP and not to the effective date of tariffs and clarified the tariffs were not retroactive. In the rehearing entry, the PUCO reaffirmed its holding that it had not authorized retroactive rates.

In April 2009, certain intervenors filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases. In May 2009, CSPCo, OPCo and the PUCO filed a motion to dismiss the writ of prohibition. In June 2009, the Ohio Supreme Court dismissed the writ of prohibition.

In June 2009, intervenors filed a motion in the ESP proceeding with the PUCO requesting CSPCo and OPCo to refund deferrals allegedly collected by CSPCo and OPCo which were created by the PUCO's approval of a temporary special arrangement between CSPCo, OPCo and Ormet, a large industrial customer. In addition, the intervenors requested that the PUCO prevent CSPCo and OPCo from collecting these revenues in the future. In June 2009, CSPCo and OPCo filed its response regarding the motion to refund amounts allegedly collected and to prevent future collections. The CSPCo and OPCo response noted that the difference in the amount deferred between the PUCO-determined market price for 2008 and the rate paid by Ormet was not collected, but instead was deferred, with PUCO authorization, as a regulatory asset for future recovery. In the rehearing entry, the PUCO did not order an adjustment to rates based on this issue. See "Ormet" section below.

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. In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period, CSPCo and OPCo each collected $12 million in pre-construction costs and incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million.

The June 2006 order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all pre-construction cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest.

In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest. In October 2008, CSPCo and OPCo filed a respond with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that CSPCo and OPCo have not commenced construction of the IGCC plant and CSPCo and OPCo believe there exist real statutory barriers to the construction of any new base load generation in Ohio, including the IGCC plant. The statement also indicated that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in the commencement of construction on a continuous course by that time.

Management continues to pursue the ultimate construction of an IGCC plant in Ohio although CSPCo and OPCo will not start construction of an IGCC plant until sufficient assurance of regulatory cost recovery exists. If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in another jurisdiction, it would have an adverse effect on future net income and cash flows. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

Ormet

In December 2008, CSPCo, OPCo and Ormet, a large aluminum company currently operating at a reduced load of approximately 400 MW, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The arrangement would be effective January 1, 2009 and remain in effect and expire upon the later of the effective date of CSPCo's and OPCo's new ESP rates and the effective date of a new arrangement between Ormet and CSPCo/OPCo as approved by the PUCO. Under the interim arrangement, Ormet would pay the then-current applicable generation tariff rates and riders and CSPCo and OPCo would defer as a regulatory asset, beginning in 2009, the difference between the PUCO-approved 2008 market price of $53.03 per MWH and the applicable generation tariff rates and riders. CSPCo and OPCo proposed to recover the deferral through the FAC mechanism they proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement. In February 2009, an intervenor filed an application for rehearing of the PUCO's interim arrangement approval. In March 2009, the PUCO granted that application for further consideration of the matters specified in the rehearing application. In the PUCO's July 2009 order discussed below, CSPCo and OPCo were directed to file an application to recover the appropriate amounts of the deferrals under the interim agreement and for the remainder of 2009.

In February 2009, as amended in April 2009, Ormet filed an application with the PUCO for approval of a proposed Ormet power contract for 2009 through 2018. Ormet proposed to pay varying amounts based on certain conditions, including the price of aluminum and the level of production. The difference between the amounts paid by Ormet and the otherwise applicable PUCO ESP tariff rate would be either collected from or refunded to CSPCo's and OPCo's retail customers.

In March 2009, the PUCO issued an order in the ESP filings which included approval of a FAC for the ESP period. The approval of an ESP FAC, together with the January 2009 PUCO approval of the Ormet interim arrangement, provided the basis to record regulatory assets of $18 million and $14 million for CSPCo and OPCo, respectively, for the differential in the approved market price of $53.03 versus the rate paid by Ormet during the first six months of 2009. These amounts are included in CSPCo's and OPCo's FAC phase-in deferral balance of $34 million and $140 million, respectively. See "Ohio Electric Security Plan Filings" section above. The pricing and deferral authority under the PUCO's January 2009 approval of the interim arrangement will continue until the 2009-2018 power contract becomes effective.

In May 2009, intervenors filed a motion with the PUCO that contends CSPCo and OPCo should be charging Ormet the new ESP rate and that no additional deferrals between the approved market price and the rate paid by Ormet should be calculated and recovered through the FAC since Ormet will be paying the new ESP rate. In May 2009, CSPCo and OPCo filed a Memorandum Contra recommending the PUCO deny the motion to cease additional deferrals. In June 2009, intervenors filed a motion with the PUCO related to Ormet in the ESP proceeding. See "Ohio Electric Security Plan Filings" section above.

In July 2009, the PUCO approved Ormet's application for a power contract through 2018 with several modifications. As modified by the PUCO, rates billed to Ormet by CSPCo and OPCo for the balance of 2009 would reflect an annual averaged rate of $38 per MWH for the periods Ormet was in full production and $35 and $34 per MWH at certain curtailed production levels. These rates are contingent upon Ormet maintaining its employment levels at 900 employees for 2009. The PUCO authorized CSPCo and OPCo to defer foregone revenue amounts (the difference between CSPCo's and OPCo's tariff rate and the rate paid by Ormet) created by the blended rate for the remainder of 2009. For 2010 through 2018, the PUCO approved the linkage of Ormet's rate to the price of aluminum but modified the agreement to include a maximum electric rate discount for Ormet that declines over time to zero in 2018 and a maximum amount of revenue foregone that ratepayers will be expected to pay via a rider in any given year. To the extent the discount exceeds the amount collectible from ratepayers, the difference can be deferred, with a long-term debt carrying charge, for future recovery. In addition, this rate is based upon Ormet maintaining at least 650 employees. For every 50 employees below that level, Ormet's maximum electric rate discount will be reduced. In July 2009, Ormet announced that it will substantially curtail operations starting in September 2009.

Hurricane Ike

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. Under the RSP, which was effective in 2008, CSPCo and OPCo could seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively, for the expected recovery of the storm restoration costs. In December 2008, the PUCO approved these regulatory assets along with a long-term debt only carrying cost on these regulatory assets. In its order approving the deferrals, the PUCO stated that the mechanism for recovery would be determined in CSPCo's and OPCo's next distribution rate filing. At June 30, 2009, CSPCo and OPCo have accrued regulatory assets of $18 million and $10 million, respectively, including the approved long-term debt only carrying costs.

Texas Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 million, respectively. Municipal customers and other intervenors appealed the PUCT true-up orders seeking to further reduce TCC's true-up recoveries. TCC also appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. The significant items appealed by TCC were:

- 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 TCC bundled out-of-the-money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant costs.

- Two federal matters regarding the allocation of off-system sales related to fuel recoveries and a potential tax normalization violation.

In March 2007, the Texas District Court judge hearing the appeals of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs and remanded this matter to the PUCT for further consideration. This remand could potentially have an adverse effect on TCC's future net income and cash flows if upheld on appeal. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness which could have a favorable effect on TCC's future net income and cash flows.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but two major respects. It reversed the District Court's unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earnings based upon the reasons discussed in the "TCC Excess Earnings" section below. The favorable commercial unreasonableness judgment entered by the District Court was not reversed. In June 2008, the Texas Court of Appeals denied intervenors' motions for rehearing. In August 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not determined if it will grant review. In January 2009, the Texas Supreme Court requested full briefing of the proceedings which concluded in June 2009.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. TNC appealed its final true-up order, which remains pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in their appeals, it could have a material favorable effect on future net income, cash flows and possibly financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a material adverse effect on future net income, cash flows and possibly financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

TCC's appeal remains outstanding related to the stranded costs true-up and related orders regarding whether the PUCT may require TCC to refund certain tax benefits to customers. Subsequent to the PUCT's ordered reduction to TCC's securitized stranded costs by certain tax benefits, the PUCT, reacting to possible IRS normalization violations, allowed TCC to defer $103 million of ordered CTC refunds for other true-up items to negate the securitization reduction. Of the $103 million, $61 million relates to the present value of certain tax benefits applied to reduce the securitization stranded generating assets and $42 million was for subsequent carrying costs. The deferral of the CTC refunds is pending resolution on whether the PUCT's securitization refund is an IRS normalization violation.

Since the deferral through the CTC refund, the IRS issued a favorable final regulation in March 2008 addressing the normalization requirements for the treatment of Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) in a stranded cost determination. Consistent with a Private Letter Ruling TCC received in 2006, the final regulations clearly state that TCC will sustain a normalization violation if the PUCT orders TCC in a final order after all appeals to flow the tax benefits to customers as part of the stranded cost true-up. TCC notified the PUCT that the final regulations were issued. The PUCT made a request to the Texas Court of Appeals for the matter to be remanded back to the PUCT for further action. In May 2008, as requested by the PUCT, the Texas Court of Appeals ordered a remand of the tax normalization issue for the consideration of this favorable additional evidence.

TCC expects that the PUCT will allow TCC to retain the deferred amounts. This will have a favorable effect on future net income as TCC will be able to amortize the deferred ADITC and EDFIT tax benefits to income over the remaining securitization period. Since management expects that the PUCT will allow TCC to retain the deferred CTC refund amounts in order to avoid an IRS normalization violation, no related interest expense has been accrued related to refunds of these amounts. If accrued, management estimates interest expense would have been approximately $8 million higher for the period July 2008 through June 2009 based on a CTC interest rate of 7.5% with $4 million relating to 2008.

If the PUCT orders TCC to return the tax benefits to customers, thereby causing a violation of the IRS normalization regulations, the violation could result in TCC's repayment to the IRS, under the normalization rules, of ADITC on all property, including transmission and distribution property. This amount approximates $102 million as of June 30, 2009. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay to the IRS its ADITC and is also required to refund ADITC to customers, it would have an unfavorable effect on future net income and cash flows. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are actually returned to ratepayers under a nonappealable final order. Management intends to continue to work with the PUCT to favorably resolve the issue and avoid the adverse effects of a normalization violation on future net income, cash flows and financial condition.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded cost recoveries from REPs in the True-up Proceeding. It is possible that TCC's stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy.

In May 2008, the Texas Court of Appeals issued a decision in TCC's True-up Proceeding determining that even though excess earnings had been previously refunded to REPs, TCC still must reduce stranded cost recoveries in its True-up Proceeding. In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset of $55 million representing a receivable from the REPs for prior excess earnings refunds made to them by TCC. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund additional amounts of excess earnings or interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would have an adverse effect on future net income and cash flows. AEP sold its affiliate REPs in December 2002. While AEP owned the affiliate REPs, TCC refunded $11 million of excess earnings to the affiliate REPs. Management cannot predict the outcome of the excess earnings remand and whether it would have an adverse effect on future net income and cash flows.

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo returned to cost-based regulation and re-applied SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of SFAS 71 regulatory accounting resulted in an $8 million ($5 million, net of tax) extraordinary loss.

In addition, effective April 2009, the generation portion of SWEPCo's Texas retail jurisdiction began accruing AFUDC (debt and equity return) instead of capitalized interest on its eligible construction balances including the Stall Unit and the Turk Plant. The accrual of AFUDC increased second quarter of 2009 net income by approximately $3 million using the last PUCT-approved return on equity rate.

OTHER TEXAS RATE MATTERS

Hurricanes Dolly and Ike

In July and September 2008, TCC's service territory in south Texas was hit by Hurricanes Dolly and Ike, respectively. TCC incurred $23 million and $2 million in incremental maintenance costs related to service restoration efforts for Hurricanes Dolly and Ike, respectively. TCC has a PUCT-approved catastrophe reserve which permits TCC to collect $1.3 million annually until the catastrophe reserve reaches $13 million. Any incremental storm-related maintenance costs can be charged against the catastrophe reserve if the total incremental maintenance costs for a storm exceed $500 thousand. In June 2008, prior to these hurricanes, TCC had a $2 million balance in its catastrophe reserve account. Therefore, TCC established a net regulatory asset for $23 million. The balance in the catastrophe reserve regulatory asset account as of June 30, 2009 is approximately $22 million.

Under Texas law and as previously approved by the PUCT in prior base rate cases, the regulatory asset will be included in rate base in the next base rate filing. In connection with the filing of the next base rate case, TCC will evaluate the existing catastrophe reserve ratepayer funding and review potential future events to determine the appropriate funding level to request to both recover the then existing regulatory asset balance and to adequately fund a reserve for future storms in a reasonable time period. TCC has no current plans to file a base rate case in 2009.

2008 Interim Transmission Rates

In March 2008, TCC and TNC filed applications with the PUCT for an annual interim update of wholesale-transmission rates. The proposed new interim transmission rates are estimated to increase annual transmission revenues by $9 million and $4 million for TCC and TNC, respectively. In May 2008, the PUCT and the FERC approved the new interim transmission rates as filed. TCC and TNC implemented the new rates effective May 2008, subject to review during the next TCC and TNC base rate case. This review could result in a refund if the PUCT finds that TCC and TNC have not prudently incurred the requested transmission investment. TCC and TNC have not recorded any provision for refund regarding the interim transmission rates because management believes these new rates are reasonable and necessary to recover costs associated with prudently incurred new transmission investment. A refund of the interim transmission rates would have an adverse impact on net income and cash flows.

2009 Interim Transmission Rates

In February 2009, TCC and TNC filed applications with the PUCT for an annual interim update of wholesale-transmission rates. The proposed new interim transmission rates are estimated to increase annual transmission revenues by $8 million and $9 million for TCC and TNC, respectively. In May 2009, the PUCT and the FERC approved the new interim transmission rates as filed. TCC and TNC implemented the new rates effective May 2009, subject to review during the next TCC and TNC base rate case. This review could result in a refund if the PUCT finds that TCC and TNC have not prudently incurred the requested transmission investment. TCC and TNC have not recorded any provision for refund regarding the interim transmission rates because management believes these new rates are reasonable and necessary to recover costs associated with prudently incurred new transmission investment. A refund of the interim transmission rates would have an adverse impact on net income and cash flows.

Texas Rate Filing

In November 2006, TCC filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rate in Texas. TCC's revised requested increase in annual base rates was $70 million based on a requested return on common equity of 10.75%.

TCC implemented the rate change in June 2007, subject to refund. In March 2008, the PUCT issued an order approving rates to collect a $20 million base rate increase based on a return on common equity of 9.96% and an additional $20 million increase in revenues related to the expiration of TCC's merger credits. In addition, depreciation expense was decreased by $7 million and discretionary fee revenues were increased by $3 million. TCC estimates the order will increase TCC's annual pretax income by $50 million. Various parties appealed the PUCT decision.

In February 2009, the Texas District Court affirmed the PUCT in most respects. However, it also ruled that the PUCT improperly denied TCC an AFUDC return on the prepaid pension asset that the PUCT ruled to be CWIP. In March 2009, various intervenors appealed the Texas District Court decision to the Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the appeals are successful, it could have an adverse effect on future net income and cash flows.

ETT

In December 2007, TCC contributed $70 million of transmission facilities to ETT, an AEP joint venture accounted for using the equity method. The PUCT approved ETT's initial rates, a request for a transfer of facilities and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in the ERCOT region. ETT was allowed a 9.96% after tax return on equity rate in those approvals. In 2008, intervenors filed a notice of appeal to the Travis County District Court. In October 2008, the court ruled that the PUCT exceeded its authority by approving ETT’s application as a stand alone transmission utility without a service area under the wrong section of the statute. Management believes that ruling is incorrect. Moreover, ETT provided evidence in its application that ETT complied with what the court determined was the proper section of the statute.

In January 2009, ETT and the PUCT filed appeals to the Texas Court of Appeals. In June 2009, the Texas governor signed a new law that clarifies the PUCT’s authority to grant CCNs to transmission-only utilities such as ETT. During 2009, TCC and TNC sold $91 million and $1 million, respectively, of additional transmission facilities to ETT. As of June 30, 2009, AEP’s net investment in ETT was $40 million. Depending upon the ultimate outcome of the appeals and any resulting remands, TCC and TNC may be required to reacquire transferred assets and projects under construction by ETT if ETT cannot obtain the appropriate approvals. As of June 30, 2009, ETT’s net investment in property, plant and equipment was $196 million, of which $61 million was under construction.

ETT, TCC and TNC are involved in transactions relating to the transfer to ETT of other transmission assets, which are in various stages of review and approval. In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the Competitive Renewable Energy Zone (CREZ) initiative. The CREZ initiative is the development of 2,400 miles of new transmission lines to transport electricity from 18,000 MWs of planned wind farm capacity in west Texas to rapidly growing cities in eastern Texas. In March 2009, the PUCT issued an order pursuant to a January 2009 decision that authorized ETT to pursue the construction of $841 million of new CREZ transmission assets and also initiated a proceeding to develop a sequence of regulatory filings for routing the CREZ transmission lines. In June 2009, ETT and other parties entered into a settlement agreement establishing dates for these filings. Pursuant to the settlement agreement, which is pending PUCT approval, ETT would make regulatory filings in 2010 and initiate construction upon receipt of PUCT approval.

Stall Unit

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

Turk Plant

See “Turk Plant” section within “Arkansas Rate Matters” for disclosure.

<u>Virginia Rate Matters</u>

Virginia E&R Costs Recovery Filing

Due to the recovery provisions in Virginia law, APCo has been deferring incremental E&R costs as incurred, excluding the equity return on in-service E&R capital investments, pending future recovery. In October 2008, the Virginia SCC approved a stipulation agreement to recover $61 million of incremental E&R costs incurred from October 2006 to December 2007 through a surcharge in 2009 which will have a favorable effect on cash flows of $61 million and on net income for the previously unrecognized equity portion of the carrying costs of approximately $11 million.

The Virginia E&R cost recovery mechanism under Virginia law ceased effective with costs incurred through December 2008. However, the 2007 amendments to Virginia's electric utility restructuring law provide for a rate adjustment clause to be requested in 2009 to recover incremental E&R costs incurred through December 2008. Under this amendment, APCo filed a request, in May 2009, to recover its unrecovered 2008 incremental deferred E&R costs plus its 2008 equity costs on in-service E&R capital investments. The hearing is scheduled to begin in October 2009.

As of June 30, 2009, APCo has $99 million of deferred Virginia incremental E&R costs (excluding $19 million of unrecognized equity carrying costs). The $99 million consists of $6 million of over-recovered costs collected under the 2008 surcharge, $25 million approved by the Virginia SCC related to the 2009 surcharge and $80 million, representing costs deferred during 2008, which were included in the May 2009 E&R filing for collection in 2010.

If the Virginia SCC were to disallow a material portion of APCo's 2008 deferred incremental E&R costs, it would have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant

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

In June 2007, APCo sought pre-approval from the WVPSC for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and 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. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with the proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo's requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. Various parties, including APCo, filed comments but the WVPSC has not taken any action.

Through June 30, 2009, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010.

Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs, which if not recoverable, would have an adverse effect on future net income and cash flows.

Mountaineer Carbon Capture Project

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO_2 capture demonstration facility. APCo and Alstom will each own part of the CO_2 capture facility. APCo will also construct and own the necessary facilities to store the CO_2. RWE AG, a German electric power and natural gas public utility, is participating in the project and is providing some funding to offset APCo's costs. APCo's estimated cost for its share of the constructed facilities is $72 million. Through June 30, 2009, APCo incurred $59 million in capitalized project costs which are included in Regulatory Assets. In May 2009, the West Virginia Department of Environmental Protection issued a permit to inject CO_2 that requires, among other items, that APCo monitor the wells for at least 20 years following the cessation of CO_2 injection. APCo plans to start injecting CO_2 in September 2009 which will result, at that time, in an asset retirement obligation and a regulatory asset at its net present value preliminary estimated to be approximately $25 million.

APCo currently earns a return on the Virginia portion of the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on the estimated September 2009 in-service Virginia jurisdictional share of its CO_2 capture and storage project costs including the related asset retirement obligation expenses. See the "Virginia Base Rate Filing" section below. Based on the favorable treatment related to the CO_2 capture demonstration facility in the last Virginia base rate case, management is deferring the carbon capture expense as a regulatory asset for future recovery. APCo plans to seek recovery of the West Virginia jurisdictional costs in its next West Virginia base rate filing which is expected to be filed in late 2009. If the deferred project costs are disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.

Virginia Base Rate Filing

The 2007 amendments to Virginia's electric utility restructuring law require that each investor-owned utility, such as APCo, file a base rate case with the Virginia SCC in 2009 in which the Virginia SCC will determine fair rates of return on common equity (ROE) for the generation and distribution services of the utility. In July 2009, APCo filed a base rate case with the Virginia SCC requesting an increase in the generation and distribution portions of base rates of $169 million annually based on a 2008 test year, as adjusted, and a 13.35% ROE inclusive of a requested 0.85% ROE performance incentive increase as permitted by law. The recovery of APCo's transmission service costs in Virginia was requested in a separate and simultaneous transmission rate adjustment clause filing. See the "Rate Adjustment Clauses" section below. The new generation and distribution base rates will be effective, subject to refund, no later than December 2009. In July 2009, APCo filed a motion with the Virginia SCC requesting permission to file, in August 2009, supplemental schedules and testimony reflecting a recent Virginia SCC's order in an unaffiliated utility's base rate case concerning the appropriate capital structure to be used in the determination of the revenue requirement.

Rate Adjustment Clauses

In 2007, the Virginia law governing the regulation of electric utility service was amended to, among other items, provide for rate adjustment clauses (RAC) beginning in January 2009 for the timely and current recovery of costs of (a) transmission services billed by an RTO, (b) demand side management and energy efficiency programs, (c) renewable energy programs, (d) environmental compliance projects and (e) new generation facilities including major unit modifications. In July 2009, APCo filed for approval of a transmission RAC simultaneous with the 2009 base rate case filing in which the Virginia jurisdictional share of transmission costs was requested for recovery through the RAC instead of through base rates. The transmission filing requested an annual increase of $24 million to be effective mid-December 2009. See the "Virginia Base Rate Filing" section above. Also, APCo plans to file for approval of an environmental RAC no later than the first quarter of 2010 to recover any unrecovered environmental costs incurred after December 2008. In accordance with Virginia law, APCo is deferring any incremental transmission and environmental costs incurred after December 2008 that are not being recovered in current revenues. As of June 30, 2009, APCo has deferred $8 million of environmental costs (excluding $1 million of unrecognized equity carrying costs) to be recovered in an environmental RAC and $6 million of transmission costs to be recovered in a 2010 transmission RAC filing. Management is evaluating whether to make other RAC filings at this time. If the Virginia SCC were to disallow a portion of APCo's deferred RAC costs, it would have an adverse effect on future net income and cash flows.

Virginia Fuel Factor Proceeding

In May 2009, APCo filed an application with the Virginia SCC to increase its fuel adjustment charge by approximately $227 million from July 2009 through August 2010. The $227 million proposed increase related to a $104 million projected under-recovery balance of fuel costs as of June 30, 2009 and $123 million of projected fuel costs for the period July 2009 through August 2010. APCo's actual under-recovered fuel balance at June 30, 2009 was $93 million. Due to the significance of the estimated required increase in fuel rates, APCo's application proposed an alternative method of collection of actual incurred fuel costs. The proposed alternative would allow APCo to recover 100% of the $104 million prior period under-recovery deferral and 50% of the $123 million increase from July 2009 through August 2010 with recovery of any remaining actual under-recovered fuel costs in APCo's next fuel factor proceeding from September 2010 through August 2011. In May 2009, the Virginia SCC ordered that neither of APCo's proposed fuel factors shall become effective, pending further review by the Virginia SCC. On August 3, 2009, the Virginia SCC issued an order. Management is presently reviewing the order, which provided for a $130 million fuel revenue increase, effective August 10, 2009. Management believes that full recovery of the $93 million under-recovered fuel balance at June 30, 2009 is probable. Management also believes that the reduction in revenues from the requested amount represents a decrease in projected fuel costs to be recovered through the approved fuel factor. Such decrease should be recoverable, if necessary, either in APCo's next fuel factor proceeding for the period September 2010 through August 2011 or through other statutory mechanisms.

West Virginia Rate Matters

APCo's and WPCo's 2009 Expanded Net Energy Cost (ENEC) Filing

In March 2009, APCo and WPCo filed an annual ENEC filing with the WVPSC for an increase of approximately $442 million for incremental fuel, purchased power and environmental compliance project expenses, to become effective July 2009. Within the filing, APCo and WPCo requested the WVPSC to allow APCo and WPCo to temporarily adopt a modified ENEC mechanism due to the distressed economy and the significance of the projected required increase. The proposed modified ENEC mechanism provides that the ENEC rate increase be phased-in with unrecovered amounts deferred for future recovery over a five-year period beginning in July 2009. The mechanism also extends cost projections out for a period of three years through June 30, 2012 and provides for three annual increases to recover projected future ENEC cost increases as well as the phase-in deferrals. APCo and WPCo are also requesting that deferred amounts that exceed the deferred amounts that would have otherwise existed under the traditional ENEC mechanism be subject to a carrying charge based upon APCo's and WPCo's weighted average cost of capital. As filed, the modified ENEC mechanism would produce three annual increases, based upon projected fuel costs and including carrying charges, of $189 million, $166 million and $172 million, effective July 2009, 2010 and 2011, respectively.

In March 2009, the WVPSC issued an order suspending the modified ENEC rate increase request until December 2009. In April 2009, APCo and WPCo filed a motion for approval of an interim rate increase of $180 million, effective July 2009 and subject to refund pending the final adjudication of the ENEC by December 2009. In April 2009, the WVPSC granted intervention to several parties and heard oral arguments from APCo, WPCo and intervenors on the requested interim ENEC filing. In June 2009, the WVPSC denied APCo's and WPCo's motion for an interim rate increase.

In May 2009, various intervenors submitted testimony supporting adjustments to APCo's and WPCo's actual and projected ENEC costs. The intervenors also proposed alternative rate phase-in plans ranging from three to five years. Specifically, the WVPSC staff and the West Virginia Consumer Advocate recommended a total increase of $376 million and $327 million, respectively, with $132 million and $130 million, respectively, being collected during the first year and suggested that the remaining rate increases for future years be determined in subsequent ENEC filings. In June 2009, APCo and WPCo filed rebuttal testimony. In the rebuttal testimony, APCo and WPCo accepted certain intervenor adjustments and reduced the requested overall increase to $398 million with a proposed first-year increase of $160 million. The primary difference between the intervenors' $130 million first-year increase and APCo's and WPCo's $160 million first-year increase is the intervenors' proposed disallowance of up to $36 million of actual and projected coal costs.

APCo and WPCo expect a decision from the WVPSC on the 2009 ENEC filing during the third quarter of 2009. If the WVPSC were to disallow a portion of APCo's and WPCo's requested increase, it could have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant

See "APCo's Filings for an IGCC Plant" section within "Virginia Rate Matters" for disclosure.

Mountaineer Carbon Capture Project

See "Mountaineer Carbon Capture Project" section within "Virginia Rate Matters" for disclosure.

Indiana Rate Matters

Indiana Base Rate Filing

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. In addition, I&M proposed to share with customers, through a proposed tracker, 50% of its off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement incorporated the $69 million annual reduction in revenues from the depreciation rate reduction in the development of the agreed to revenue increase of $44 million including a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue for PJM, net emission allowance and demand side management (DSM) costs. The agreement also establishes an off-system sales sharing mechanism and other provisions which include continued funding for the eventual decommissioning of the Cook Plant.

In March 2009, the IURC approved the settlement agreement, with modifications, that provides for an annual increase in revenues of $42 million including a $19 million increase in revenue from base rates, net of the depreciation rate reduction, and a $23 million increase in tracker revenue. The IURC order removed base rate recovery of the DSM costs but established a tracker with an initial zero amount for DSM costs and required I&M to collaborate with other parties regarding future I&M DSM programs, adjusted the sharing of off-system sales margins to 50% above $37.5 million included in base rates and approved the recovery of $7.3 million of previously expensed NSR and OPEB costs which favorably affected first quarter of 2009 net income. In addition, the IURC order requires I&M to review and file a final report by December 2009 on the effectiveness of the Interconnection Agreement including I&M's relationship with PJM. The new rates were implemented in March 2009.

Rockport and Tanners Creek Plants Environmental Facilities

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NO_x and mercury from its existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek Plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport Plant. I&M is requesting to depreciate the ACI systems over an accelerated 10-year period and the SNCR systems over the 11-year remaining useful life of the Tanners Creek generating units.

I&M's petition also requested the IURC to approve a rate adjustment mechanism for unrecovered carrying costs during the remaining construction period of these environmental facilities and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the facilities are placed in service. I&M also requested the IURC to authorize the deferral of the remaining construction period carrying costs and any in-service cost of service for these facilities until such costs are recognized in the requested rate adjustment mechanism. Through June 30, 2009, I&M incurred $11 million and $8 million in capitalized facilities cost related to the Rockport and Tanners Creek Plants, respectively, which are included in CWIP. Since the Indiana base rate order included recovery of emission allowance costs, that portion of the cost of service of these facilities will not be included in this requested rate adjustment mechanism.

In May 2009, a settlement agreement (settlement) was filed with the IURC recommending approval of a CPCN and a rider to recover a weighted average cost of capital on I&M's investment in the SNCR system and the ACI system at December 31, 2008, plus future depreciation and operation and maintenance costs. The settlement will allow I&M to file subsequent requests in six month intervals to update the rider for additional investments in the SNCR systems and the ACI systems and for true-ups of the rider revenues to actual costs. In June 2009, the IURC approved the settlement which will result in an annualized increase in rates of $8 million effective August 1, 2009.

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for the period of April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of increased coal prices, the shutdown of the Cook Plant Unit 1 (Unit 1) due to turbine vibrations and a projection for the future period of fuel costs including Unit 1 shutdown replacement power costs. The filing also included an adjustment, beginning coincident with the receipt of insurance proceeds in mid-December 2008, to eliminate the incremental fuel cost of replacement power post mid-December 2008 with a portion of the insurance proceeds from the Unit 1 accidental outage policy. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. I&M reached an agreement in February 2009 with intervenors, which was approved by the IURC in March 2009, to collect the under-recovery over twelve months instead of over six months as proposed. Under the agreement, the fuel factor was placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown, the use of the insurance proceeds and I&M's fuel procurement practices. The order provided for the shutdown issues to be resolved subsequent to the date Unit 1 returns to service, which if temporary repairs are successful, could occur as early as October 2009. Consistent with the March 2009 IURC order, I&M made its semi-annual fuel filing in July 2009 requesting an increase of approximately $4 million for the period October 2009 through March 2010. The projected fuel costs for the period included the second half of the under-recovered balance approved in the March 2009 order plus recovery of a $12 million under-recovered balance from the reconciliation period of December 2008 through May 2009. Management cannot predict the outcome of the pending proceedings, including the treatment of the insurance proceeds, and whether any fuel clause revenues will have to be refunded as a result which could adversely affect future net income and cash flows.

Michigan Rate Matters

2008 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2009, I&M filed with the Michigan Public Service Commission (MPSC) its 2008 PSCR reconciliation. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Plant Unit 1 accidental outage policy, which began in mid-December 2008. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. In May 2009, the MPSC set a procedural schedule for testimony and hearings to be held in the fourth quarter of 2009. A final order is anticipated in the first quarter of 2010. Management is unable to predict the outcome of this proceeding and its possible adverse effect on future net income and cash flows.

Oklahoma Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

Proceedings addressing PSO's historic fuel costs from 2001 through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement. For further discussion and estimated effect on net income, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that concluded it was a FERC jurisdictional matter which allowed PSO to retain the $42 million it recovered from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending.

2007 Fuel and Purchased Power

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. In June 2009, the OCC staff recommended the OCC accept PSO's fuel adjustment clause and find that PSO's fuel procurement practices, policies and decisions were prudent. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

2008 Oklahoma Base Rate Filing

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million (later adjusted to $127 million) on an annual basis. At the time of the filing, PSO was recovering $16 million a year for costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO's net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues based on a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO's program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. The deferral was recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. During the second quarter of 2009, PSO accrued a regulatory liability of approximately $1 million related to a delay in installing gridSMART technologies as the OCC final order had included $2 million for this purpose.

PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment contained within the OCC final order to remove prepaid pension fund contributions from rate base. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several rate case issues. If the Attorney General or the intervenor's Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

Louisiana Rate Matters

2008 Formula Rate Filing

In April 2008, SWEPCo filed its first formula rate filing under an approved three-year formula rate plan (FRP) which would increase its annual Louisiana retail rates by $11 million in August 2008 in order to earn an adjusted return on common equity of 10.565%. In August 2008, SWEPCo implemented the FRP rates, subject to refund. During the second quarter of 2009, SWEPCo recorded a provision for refund of approximately $1 million after reaching a settlement in principle with intervenors. SWEPCo is currently working with the parties to the settlement to prepare a written agreement to be filed with the LPSC for approval.

2009 Formula Rate Filing

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional $4 million effective in August 2009 pursuant to the approved FRP. Since the rates as filed are in compliance with the FRP methodology previously approved by the LPSC, management expects that the LPSC will allow SWEPCo to implement the FRP rate increase as filed, subject to refund.

Stall Unit

In May 2006, SWEPCo announced plans to build an intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit (Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $432 million, including $48 million of AFUDC, and is expected to be in service in mid-2010. In March 2007, the PUCT approved SWEPCo's request for a certificate of necessity for the facility based on a prior cost estimate.

The Louisiana Department of Environmental Quality issued an air permit for the Stall Unit in March 2008. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million including AFUDC and excluding related transmission costs. In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC staff filed testimony in March 2009 supporting the approval of the plant. The APSC staff also recommended that costs be capped at $445 million including AFUDC and excluding related transmission costs. In June 2009, the APSC approved the construction of the unit with a series of conditions consistent with those designated by the LPSC, including a requirement for an independent monitor and a $445 million cost cap.

As of June 30, 2009, SWEPCo has capitalized construction costs of $322 million, including AFUDC, and has contractual construction commitments of an additional $56 million with the total estimated cost to complete the unit at $432 million. If the total final cost of the Stall Unit exceeds the $445 million cost cap, it would have an adverse effect on net income and cash flows. If for any other reason SWEPCo cannot recover its capitalized costs, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Turk Plant

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

Arkansas Rate Matters

Turk Plant

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. In 2007, the Oklahoma Municipal Power Authority (OMPA) acquired an approximate 7% ownership interest in the Turk Plant, paid SWEPCo $13.5 million for its share of the accrued construction costs and began paying its proportional share of ongoing costs. During the first quarter of 2009, the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) acquired ownership interests in the Turk Plant representing approximately 12% and 8%, respectively, and paid SWEPCo $104 million in the aggregate for their shares of accrued construction costs, and began paying their proportional shares of ongoing costs. The joint owners are billed monthly for their share of the on-going construction costs exclusive of AFUDC. Through June 30, 2009, the joint owners had paid SWEPCo $173 million for their share of the Turk construction expenditures. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's share estimated to cost $1.2 billion, excluding AFUDC. In addition, SWEPCo will own 100% of the related transmission facilities which are currently estimated to cost $131 million, excluding AFUDC.

In November 2007, the APSC granted approval for SWEPCo to build the Turk Plant in Arkansas at the existing site by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Certain intervenors appealed the APSC's decision to grant the CECPN to build the Turk Plant to the Arkansas Court of Appeals. In January 2009, the APSC granted additional CECPNs allowing SWEPCo to construct Turk-related transmission facilities. Intervenors also appealed these CECPN orders to the Arkansas Court of Appeals.

In June 2009, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN permitting construction of the Turk Plant to serve Arkansas retail customers. The decision was based upon the Arkansas Court of Appeals' interpretation of the statute that governs the certification process and its conclusion that the APSC did not fully comply with that process. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the generating plant and the proposed transmission facilities' construction and location should all have been considered by the APSC in a single docket instead of separate dockets. Both SWEPCo and the APSC petitioned the Arkansas Supreme Court to review the Arkansas Court of Appeals decision. SWEPCo's petition for review had the effect of staying the Arkansas Court of Appeals decision and, while the appeals are pending, SWEPCo is continuing construction of the Turk Plant. Management believes that the APSC properly interpreted and applied the Arkansas statutes governing the Turk Plant certification process and that SWEPCo's grounds for seeking review are strong.

If the decision of the Court of Appeals is not reversed by the Supreme Court of Arkansas, SWEPCo and the other joint owners of the Turk Plant will evaluate their options. Depending on the time taken by the Arkansas Supreme Court to consider the case and the reasoning of the Arkansas Supreme Court when it acts on SWEPCo's and the APSC's petitions, the construction schedule and/or the cost could be adversely affected. Should the appeal be unsuccessful, additional proceedings or alternative contractual ownership and operational responsibilities could be required.

In March 2008, the LPSC approved the application to construct the Turk Plant. In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions as being unlawful. If the cost cap restrictions are upheld and construction or CO_2 emission costs exceed the restrictions, it could have an adverse effect on net income, cash flows and possibly financial condition. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in Federal District Court by certain Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals. In January 2009, SWEPCo filed a motion to dismiss the appeal, which was granted in March 2009.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. In December 2008, certain parties filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while the appeal of the Turk Plant's permit is heard. In June 2009, hearings on the air permit appeal were held at the APCEC. A decision is still pending and not expected until 2010. These same parties have filed a petition with the Federal EPA to review the air permit. If the air permit were to be remanded or ultimately revoked, construction of the Turk Plant could be suspended or cancelled. The Turk Plant cannot be placed into service without an air permit.

SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers an inadvertent impact on approximately 2.5 acres of wetlands at the Turk Plant construction site prior to the receipt of the permit. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas outside of the proposed Army Corps of Engineers permitted areas of the Turk Plant pending the Army Corps of Engineers review. SWEPCo has entered into a Consent Agreement and Final Order with the Federal EPA to resolve liability for the inadvertent impact and agreed to pay a civil penalty of approximately $29 thousand.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. To date, the report's effect is only advisory, but if legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's ability to complete construction on schedule in 2012 and on budget.

If the Turk Plant cannot be completed and placed in service, SWEPCo would seek approval to recover its prudently incurred capitalized construction costs including any cancellation fees and a return on unrecovered balances through rates in all of its jurisdictions. As of June 30, 2009, and excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $570 million of expenditures (including AFUDC and related transmission costs of $10 million) and has contractual construction commitments for an additional $582 million (including related transmission costs of $7 million). As of June 30, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $136 million (including related transmission cancellation fees of $1 million).

Management believes that SWEPCo's planning, certification and construction of the Turk Plant to date have been in material compliance with all applicable laws and regulations, except for the inadvertent wetlands intrusion discussed above. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if for any reason SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would adversely impact net income, cash flows and possibly financial condition unless the resultant losses can be fully recovered, with a return on unrecovered balances, through rates in all of its jurisdictions.

Arkansas Base Rate Filing

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to recover financing costs related to the construction of the Stall Unit and Turk Plant. In June 2009, the APSC staff recommended a $15.5 million increase based on a return on equity of 10.25% and did not recommend any riders based upon the Arkansas State Court of Appeals' decision to reverse the APSC's grant of a Certificate of Environmental Compatibility and Public Need for the Turk Plant. See "Turk Plant" section above. In June 2009, the Arkansas Attorney General recommended a $12.9 million increase based on a return on equity of 10% and recommended part of the requested rider for the Stall Unit only. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

In January 2009, an ice storm struck in northern Arkansas affecting SWEPCo's customers. SWEPCo incurred approximately $4 million in incremental operation and maintenance expenses above the estimated amount of storm restoration costs included in existing base rates. In May 2009, SWEPCo filed an application with the APSC seeking authority to defer the $4 million of expensed incremental operation and maintenance costs and to address the recovery of these deferred expenses in the pending base rate case. Staff testimony in this case supports SWEPCo's request, subject to an audit of the incurred costs. In July 2009, the APSC issued an order approving the deferral request subject to investigation, analysis and audit of the costs. Management is unable to predict the outcome of this application.

Stall Unit

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

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary 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. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues.

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 should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's 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. AEP and SECA ratepayers are engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. The balance in the reserve for future settlements as of June 30, 2009 was $34 million. As of June 30, 2009, there were no in-process settlements.

Management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims cannot be settled and are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this review will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. The AEP East companies sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. In January and March 2009, the AEP East companies received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, the AEP East companies are now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of the AEP East companies' transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings to reflect the resultant additional transmission cost reductions. Management is unable to predict the outcome of this case.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund reflecting the sharing. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction amount to be included in the March 2009 fuel cost report submitted to the PUCT. PSO began refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. In April 2009, TCC and TNC filed their Advanced Metering System (AMS) with the PUCT proposing to invest in AMS to be recovered through customer surcharges beginning in October 2009. In the filing, TCC and TNC proposed to apply the SIA recorded customer refunds including interest to reduce the AMS investment and the resultant associated customer surcharge. SWEPCo is working with the APSC and the LPSC to determine the effect the FERC order will have on retail rates. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding related future state regulatory proceedings is adequate.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA entered into in 1984, as amended, that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations operated at 345kV and above. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, WPCo and KGPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse the majority of PJM transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. Management is unable to predict the outcome of this proceeding and the effect, if any, it will have on future net income and cash flows due to timing of implementation by various state regulators.

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 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

We record certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." In addition, we adopted FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" effective December 31, 2008. 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 and debt service reserves. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At June 30, 2009, the maximum future payments for all the LOCs issued under the two $1.5 billion credit facilities are approximately $113 million with maturities ranging from July 2009 to July 2010.

We have a $627 million 3-year credit agreement. As of June 30, 2009, $372 million of letters of credit with maturities ranging from May 2010 to June 2010 were issued by subsidiaries under the $627 million 3-year credit agreement to support variable rate Pollution Control Bonds. We had a $350 million 364-day credit agreement that expired in April 2009.

Guarantees Of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. 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. A new study is in process to include new, expanded areas of the mine. As of June 30, 2009, SWEPCo has collected approximately $40 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $22 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $16 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 to customers 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 sale agreements is discussed in the 2008 Annual Report, "Dispositions" section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.2 billion. Approximately $1 billion of the maximum exposure relates to the Bank of America (BOA) litigation (see "Enron Bankruptcy" section of this note), of which the probable payment/performance risk is $437 million and is recorded in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets as of June 30, 2009. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2010 and 2011, we will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, we signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. We expect to enter into additional replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2010 and 2011.

For equipment under the GE master lease agreements that expire prior to 2011, 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. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual 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 actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At June 30, 2009, the maximum potential loss for these lease agreements was approximately $8 million assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of June 30, 2009.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five-year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss.

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 alleged that a unit jointly owned by CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. at the Beckjord Station was modified in violation of the NSR requirements of the CAA.

The Beckjord case had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. Following a second liability trial, the jury again found no liability at the jointly-owned Beckjord unit. Beckjord is operated by Duke Energy Ohio, Inc.

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. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs. The consent decree was entered as a final order in June 2008.

In February 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality was improper. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. We are unable to predict the timing of any future action by the Federal EPA or the effect of such actions on our net income, 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 dismissal of this lawsuit was appealed to the

Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 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 U.S. Supreme Court's decision on this case which we provided in 2007. We believe the actions are without merit and intend to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. We believe the action is without merit and intend to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms and started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $4 million of expense during 2008. Based upon updated information, I&M recorded additional expense of $3 million in March 2009. As the remediation work is completed, I&M's cost may continue to increase. I&M cannot predict the amount of additional cost, if any.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several of our units utilizing the JBR technology. The retrofits on two units are operational. Due to unexpected operating results, we completed an extensive review of the design and manufacture of the JBR internal components. Our review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. We intend to pursue our contractual and other legal remedies if we are unable to resolve these issues with Black & Veatch. If we are unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

The refueling outage scheduled for the fall of 2009 for Unit 1 was rescheduled to the spring of 2010. Management anticipates that the loss of capacity from Unit 1 will not affect I&M's ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.

I&M maintains property insurance through NEIL with a $1 million deductible. As of June 30, 2009, we recorded $54 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursement from NEIL for the cost incurred to date to repair the property damage. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In 2009, I&M recorded $99 million in revenues, including $9 million that were deferred at December 31, 2008, related to the accidental outage policy. In 2009, I&M applied $40 million of the accidental outage insurance proceeds to reduce customer bills. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

TEM Litigation

We 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 (PPA). Beginning May 1, 2003, we 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.

In January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us $255 million. We recorded the $255 million as a pretax gain in January 2008 under Asset Impairments and Other Related Charges on our Condensed Consolidated Statements of Income. This settlement related to the Plaquemine Cogeneration Facility which we sold in 2006.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 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, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the 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. This dispute is being litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In February 2004, 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 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. 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 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. In April 2005, the Judge entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. Trial in federal court in Texas was continued pending a decision on the motions for summary judgment in the New York case.

In August 2007, the judge in the New York action issued a decision granting BOA summary judgment and dismissed our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately $347 million plus interest. In August 2008, the court entered a final judgment of $346 million (the original judgment less $1 million BOA would have incurred to remove 55 BCF of natural gas from the Bammel storage facility) and clarified the interest calculation method. We appealed and posted a bond covering the amount of the judgment entered against us. The appeal was briefed during the first quarter of 2009. Oral argument remains to be scheduled. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed this award and posted bond covering that amount.

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. After recalculation for the final judgment, the liability for the BOA litigation was $437 million and $433 million including interest at June 30, 2009 and December 31, 2008, respectively. These liabilities are included in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets.

Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed in Federal District Court, Columbus, Ohio against AEP, certain executives and AEP's 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. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. Two of the three actions were dropped voluntarily by the plaintiffs in those cases. In 2006, the court entered judgment in the remaining case, denying the plaintiff's motion for class certification and dismissing all claims without prejudice. In 2007, the appeals court reversed the trial court's decision and held that the plaintiff did have standing to pursue his claim. The appeals court remanded the case to the trial court to consider the issue of whether the plaintiff is an adequate representative for the class of plan participants. In September 2008, the trial court denied the plaintiff's motion for class certification and ordered briefing on whether the plaintiff may maintain an ERISA claim on behalf of the Plan in the absence of class certification. In March 2009, the court granted a motion to intervene on behalf of an individual seeking to intervene as a new plaintiff. In July 2009, at the plaintiff's request, the court ordered, without prejudice, the dismissal of the intervening plaintiff's claims and the withdrawal of the motion to certify a class. We will continue to defend against the remaining claim.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, 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 also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In June 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we recorded for the remaining cases is adequate.

Rail Transportation Litigation

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied our motion to dismiss the case. We intend to vigorously defend against these allegations. We believe a provision recorded in 2008 should be sufficient.

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. In 2003, the FERC rejected the complaint. In 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. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. We believe a provision recorded in 2008 should be sufficient. We 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. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.

5. ACQUISITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

2009

Oxbow Mine Lignite (Utility Operations segment)

In April 2009, SWEPCo agreed to purchase 50% of the Oxbow Mine lignite reserves for $13 million and Dolet Hills Lignite Company, LLC agreed to purchase 100% of all associated mining equipment and assets for $16 million from the North American Coal Corporation and its affiliates, Red River Mining Company and Oxbow Property Company, LLC. Cleco Power LLC (Cleco) will acquire the remaining 50% interest in the lignite reserves for $13 million. SWEPCo expects to complete the transaction in the fourth quarter of 2009. Consummation of the transaction is subject to regulatory approval by the LPSC and the APSC and the transfer of other regulatory instruments. If approved, DHLC will acquire and own the Oxbow Mine mining equipment and related assets and it will operate the Oxbow Mine. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and Cleco's jointly-owned Dolet Hills Generating Station.

2008

Erlbacher companies (AEP River Operations segment)

In June 2008, AEP River Operations LLC purchased certain barging assets from Missouri Barge Line Company, Missouri Dry Dock and Repair Company and Cape Girardeau Fleeting, Inc. (collectively known as Erlbacher companies) for $35 million. These assets were incorporated into AEP River's operations which will diversify its customer base.

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 2009 and 2008 related to discontinued operations:

Three Months Ended June 30,	U.K. Generation (a) (in millions)
2009 Revenue	$ -
2009 Pretax Income	-
2009 Earnings, Net of Tax	-
2008 Revenue	$ -
2008 Pretax Income	2
2008 Earnings, Net of Tax	1

Six Months Ended June 30,	U.K. Generation (a) (in millions)
2009 Revenue	$ -
2009 Pretax Income	-
2009 Earnings, Net of Tax	-
2008 Revenue	$ -
2008 Pretax Income	2
2008 Earnings, Net of Tax	1

(a) The 2008 amounts relate to final proceeds received for the sale of land related to the sale of U.K. Generation.

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, 2009 and 2008.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost for the plans for the three and six months ended June 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 11	$ 11
Interest Cost	64	62	28	28
Expected Return on Plan Assets	(81)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	6	7
Amortization of Net Actuarial Loss	15	10	10	2
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 52	$ 50	$ 21	$ 21
Interest Cost	127	125	55	56
Expected Return on Plan Assets	(161)	(168)	(40)	(56)
Amortization of Transition Obligation	-	-	13	14
Amortization of Net Actuarial Loss	30	19	21	5
Net Periodic Benefit Cost	$ 48	$ 26	$ 70	$ 40

7. BUSINESS SEGMENTS

As outlined in our 2008 Annual Report, our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable 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.

AEP River Operations

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- 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, investment income, interest income and interest expense and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually liquidate and completely expire in 2011.
- The first quarter 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the three and six months ended June 30, 2009 and 2008 and balance sheet information as of June 30, 2009 and December 31, 2008. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Three Months Ended June 30, 2009						
Revenues from:						
External Customers	$ 3,035 (d)	$ 105	$ 58	$ 4	$ -	$ 3,202
Other Operating Segments	21 (d)	3	1	5	(30)	-
Total Revenues	$ 3,056	$ 108	$ 59	$ 9	$ (30)	$ 3,202
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 327	$ 1	$ 4	$ (10)	$ -	$ 322
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	322	1	4	(10)	-	317
Less: Net Income Attributable to Noncontrolling Interests	1	-	-	-	-	1
Net Income (Loss) Attributable to AEP Shareholders	321	1	4	(10)	-	316
Less: Preferred Stock Dividend Requirements of Subsidiaries	-	-	-	-	-	-
Earnings (Loss) Attributable to AEP Common Shareholders	$ 321	$ 1	$ 4	$ (10)	$ -	$ 316

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Three Months Ended June 30, 2008						
Revenues from:						
External Customers	$ 3,200 (d)	$ 144	$ 137	$ 65	$ -	$ 3,546
Other Operating Segments	113 (d)	7	(26)	(57)	(37)	-
Total Revenues	$ 3,313	$ 151	$ 111	$ 8	$ (37)	$ 3,546
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 264	$ 3	$ 26	$ (12)	$ -	$ 281
Discontinued Operations, Net of Tax	-	-	-	1	-	1
Net Income (Loss)	264	3	26	(11)	-	282
Less: Net Income Attributable to Noncontrolling Interests	1	-	-	-	-	1
Net Income (Loss) Attributable to AEP Shareholders	263	3	26	(11)	-	281
Less: Preferred Stock Dividend Requirements of Subsidiaries	-	-	-	-	-	-
Earnings (Loss) Attributable to AEP Common Shareholders	$ 263	$ 3	$ 26	$ (11)	$ -	$ 281

Six Months Ended June 30, 2009	Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 6,302 (d)	$ 228	$ 145	$ (15)	$ -	$ 6,660
Other Operating Segments	21 (d)	9	6	27	(63)	-
Total Revenues	$ 6,323	$ 237	$ 151	$ 12	$ (63)	$ 6,660
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 673	$ 12	$ 28	$ (28)	$ -	$ 685
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	668	12	28	(28)	-	680
Less: Net Income Attributable to Noncontrolling Interests	3	-	-	-	-	3
Net Income (Loss) Attributable to AEP Shareholders	665	12	28	(28)	-	677
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	-	-	-	-	1
Earnings (Loss) Attributable to AEP Common Shareholders	$ 664	$ 12	$ 28	$ (28)	$ -	$ 676

Six Months Ended June 30, 2008	Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 6,210 (d)	$ 282	$ 408	$ 113	$ -	$ 7,013
Other Operating Segments	397 (d)	11	(238)	(100)	(70)	-
Total Revenues	$ 6,607	$ 293	$ 170	$ 13	$ (70)	$ 7,013
Income Before Discontinued Operations and Extraordinary Loss	$ 677	$ 10	$ 27	$ 143	$ -	$ 857
Discontinued Operations, Net of Tax	-	-	-	1	-	1
Net Income	677	10	27	144	-	858
Less: Net Income Attributable to Noncontrolling Interests	3	-	-	-	-	3
Net Income Attributable to AEP Shareholders	674	10	27	144	-	855
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	-	-	-	-	1
Earnings Attributable to AEP Common Shareholders	$ 673	$ 10	$ 27	$ 144	$ -	$ 854

June 30, 2009	Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments (c)	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 49,976	$ 380	$ 570	$ 10	$ (238)	$ 50,698
Accumulated Depreciation and Amortization	16,925	80	154	8	(28)	17,139
Total Property, Plant and Equipment – Net	$ 33,051	$ 300	$ 416	$ 2	$ (210)	$ 33,559
Total Assets	$ 44,981	$ 421	$ 782	$ 15,055	$ (14,901)(b)	$ 46,338

December 31, 2008	Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustment (c)	Consolidated
	(in millions)					
Total Property, Plant and Equipment	$ 48,997	$ 371	$ 565	$ 10	$ (233)	$ 49,710
Accumulated Depreciation and Amortization	16,525	73	140	8	(23)	16,723
Total Property, Plant and Equipment – Net	$ 32,472	$ 298	$ 425	$ 2	$ (210)	$ 32,987
Total Assets	$ 43,773	$ 439	$ 737	$ 14,501	$ (14,295)(b)	$ 45,155

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually liquidate and completely expire in 2011.
- The first quarter 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

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

(c) Includes eliminations due to an intercompany capital lease.

(d) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This is offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of $(1) million and $26 million for the three months ended June 30, 2009 and 2008, respectively, and $(6) million and $238 million for the six months ended June 30, 2009 and 2008, respectively. The Generation and Marketing segment also reports these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP will end in December 2009.

8. DERIVATIVES AND HEDGING

Objectives for Utilization of Derivative Instruments

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and to a lesser extent foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risk using derivative instruments.

Strategies for Utilization of Derivative Instruments to Achieve Objectives

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value based on our open trading positions by utilizing both economic and formal SFAS 133 hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

We enter into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of June 30, 2009:

Notional Volume of Derivative Instruments
June 30, 2009

Primary Risk Exposure		Volume	Unit of Measure
		(in millions)	
Commodity:			
Power		590	MWHs
Coal		56	Tons
Natural Gas		192	MMBtu
Heating Oil and Gasoline		8	Gallons
Interest Rate	$	421	USD
Interest Rate and Foreign Currency	$	497	USD

Fair Value Hedging Strategies

At certain times, we enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Currently, this strategy is not actively employed.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to fuel price volatility. We enter into financial gasoline and heating oil derivative contracts in order to mitigate price risk of our future fuel purchases. We do not hedge all of our fuel price risk. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. We do not hedge all foreign currency exposure.

Accounting for Derivative Instruments and the Impact on Our Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to FSP FIN 39-1, we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2009 and December 31, 2008 balance sheets, we netted $35 million and $11 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $106 million and $43 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following table represents the gross fair value impact of our derivative activity on our Condensed Consolidated Balance Sheet as of June 30, 2009:

Fair Value of Derivative Instruments
June 30, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency**	**Other (b)**	**Total**
		(in millions)			
Current Risk Management Assets	$ 2,006	$ 37	$ 30	$ (1,738)	$ 335
Long-term Risk Management Assets	885	5	-	(510)	380
Total Assets	2,891	42	30	(2,248)	715
Current Risk Management Liabilities	1,914	31	3	(1,790)	158
Long-term Risk Management Liabilities	693	4	2	(561)	138
Total Liabilities	2,607	35	5	(2,351)	296
Total MTM Derivative Contract Net Assets (Liabilities)	$ 284	$ 7	$ 25	$ 103	$ 419

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Consolidated Balance Sheet on a net basis in accordance with FIN 39 "Offsetting of Amounts Related to Certain Contracts."
(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The table below presents our MTM activity of derivative risk management contracts for the three and six months ended June 30, 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
	(in millions)	
Utility Operations Revenue	$ 33	$ 99
Other Revenue	5	18
Regulatory Assets	-	(1)
Regulatory Liabilities	26	81
Total Gain on Risk Management Contracts	$ 64	$ 197

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Condensed Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Condensed Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Condensed Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized and realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with SFAS 71.

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Condensed Consolidated Statements of Income. During the three and six months ended June 30, 2009, we did not employ any fair value hedging strategies. During the three and six months ended June 30, 2008, we designated interest rate derivatives as fair value hedges and did not recognize any hedge ineffectiveness related to these derivative transactions.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale in our Condensed Consolidated Statements of Income, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to commodities. During the three and six months ended June 30, 2009 and 2008, we recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, we executed financial heating oil and gasoline derivative contracts to hedge the price risk of our diesel fuel and gasoline purchases. We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Other Operation and Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Condensed Consolidated Statements of Income. We do not hedge all fuel price risk exposure. During the three and six months ended June 30, 2009, we recognized no hedge ineffectiveness related to this hedge strategy.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2009, we recognized a gain of $7 million in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated as cash flow hedges. During the three and six months ended June 30, 2008, we recognized immaterial amounts in Interest Expense related to hedge ineffectiveness.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Depreciation and Amortization expense in our Condensed Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure. During the three and six months ended June 30, 2009 and 2008, we recognized no hedge ineffectiveness related to this hedge strategy.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges

For the Three Months Ended June 30, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Beginning Balance in AOCI as of April 1, 2009	$ 9	$ (28)	$ (19)
Changes in Fair Value Recognized in AOCI	-	15	15
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Utility Operations Revenue	(4)	-	(4)
Other Revenue	(4)	-	(4)
Purchased Electricity for Resale	6	-	6
Interest Expense	-	2	2
Regulatory Assets	1	-	1
Regulatory Liabilities	(2)	-	(2)
Ending Balance in AOCI as of June 30, 2009	$ 6	$ (11)	$ (5)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Beginning Balance in AOCI as of January 1, 2009	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(3)	15	12
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Utility Operations Revenue	(6)	-	(6)
Other Revenue	(6)	-	(6)
Purchased Electricity for Resale	14	-	14
Interest Expense	-	3	3
Regulatory Assets	3	-	3
Regulatory Liabilities	(3)	-	(3)
Ending Balance in AOCI as of June 30, 2009	$ 6	$ (11)	$ (5)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheet at June 30, 2009 were:

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
June 30, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 30	$ 30	$ 60
Hedging Liabilities (a)	(23)	(5)	(28)
AOCI Gain (Loss) Net of Tax	6	(11)	(5)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	6	(5)	1

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Condensed Consolidated Balance Sheet.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of June 30, 2009, the maximum length of time that we are hedging (with SFAS 133 designated contracts) our exposure to variability in future cash flows related to forecasted transactions is 41 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody’s, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody’s to estimate probability of default that corresponds to an implied external agency credit rating.

We use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We believe that a downgrade below investment grade is unlikely. As of June 30, 2009, the aggregate value of such contracts was $61 million and AEP was not required to post any collateral. We would have been required to post $61 million of collateral at June 30, 2009 if our credit ratings had declined below investment grade of which $55 million was attributable to our RTO and ISO activities.

9. FAIR VALUE MEASUREMENTS

With the adoption of three new accounting standards, we are required to provide certain fair value disclosures which we previously were only required to provide in our annual report. The new standards did not change the method to calculate the amounts reported on the Condensed Consolidated Balance Sheets.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt at June 30, 2009 and December 31, 2008 are summarized in the following table:

	June 30, 2009		December 31, 2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 16,696	$ 16,600	$ 15,983	$ 15,113

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell insurance company and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities in accordance with the provisions of SFAS 115, “Accounting for Certain Investments in Debt and Equity Securities” (SFAS 115). We do not have any investments classified as trading or held-to-maturity.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities, if any, reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

In evaluating potential impairment of equity securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions.

The following is a summary of Other Temporary Investments:

	June 30, 2009				December 31, 2008			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Other Temporary Investments				(in millions)				
Cash (a)	$ 199	$ -	$ -	$ 199	$ 243	$ -	$ -	$ 243
Debt Securities	56	-	-	56	56	-	-	56
Equity Securities	18	16	-	34	27	11	10	28
Total Other Temporary Investments	$ 273	$ 16	$ -	$ 289	$ 326	$ 11	$ 10	$ 327

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the three and six months ended June 30, 2009:

	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
		(in millions)		
Three Months Ended	$ -	$ 1	$ -	$ -
Six Months Ended	-	1	-	-

In June 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell insurance company. At June 30, 2009, we had no Other Temporary Investments with an unrealized loss position. At December 31, 2008, the fair value of corporate equity securities with an unrealized loss position was $17 million and we had no investments in a continuous unrealized loss position for more than twelve months. At June 30, 2009, the fair value of debt securities are primarily debt based mutual funds with short-term, intermediate and long-term maturities.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether the investor has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment, among other things, is based on whether the investor has the ability and intent to hold the investment to recover its value. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions' liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at June 30, 2009 and December 31, 2008:

	June 30, 2009			December 31, 2008		
	Estimated Fair Value	**Gross Unrealized Gains**	**Other-Than-Temporary Impairments**	**Estimated Fair Value**	**Gross Unrealized Gains**	**Other-Than-Temporary Impairments**
			(in millions)			
Cash	$ 16	$ -	$ -	$ 18	$ -	$ -
Debt Securities	767	28	(3)	773	52	(3)
Equity Securities	485	145	(135)	469	89	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,268	$ 173	$ (138)	$ 1,260	$ 141	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2009:

	Proceeds From Investment Sales	**Purchases of Investments**	**Gross Realized Gains on Investment Sales**	**Gross Realized Losses on Investment Sales**
		(in millions)		
Three Months Ended	$ 253	$ 264	$ 6	$ (1)
Six Months Ended	411	442	9	(1)

The amortized cost of debt securities was $739 million and $721 million as of June 30, 2009 and December 31, 2008, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at June 30, 2009 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 40
1 year – 5 years	214
5 years – 10 years	242
After 10 years	271
Total	$ 767

Fair Value Measurements of Financial Assets and Liabilities

As described in our 2008 Annual Report, SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Derivatives, Hedging and Fair Value Measurements note within the 2008 Annual Report should be read in conjunction with this report.

Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

The following tables set forth by level, within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009 and December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents					
Cash and Cash Equivalents (a)	$ 278	$ -	$ -	$ 80	$ 358
Debt Securities (b)	-	-	-	-	-
Total Cash and Cash Equivalents	278	-	-	80	358
Other Temporary Investments					
Cash and Cash Equivalents (a)	167	-	-	32	199
Debt Securities (c)	56	-	-	-	56
Equity Securities (d)	34	-	-	-	34
Total Other Temporary Investments	257	-	-	32	289
Risk Management Assets					
Risk Management Contracts (e)	48	2,733	92	(2,250)	623
Cash Flow Hedges (e)	6	67	-	(13)	60
Dedesignated Risk Management Contracts (f)	-	-	-	32	32
Total Risk Management Assets	54	2,800	92	(2,231)	715
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (g)	-	5	-	11	16
Debt Securities (h)	-	767	-	-	767
Equity Securities (d)	485	-	-	-	485
Total Spent Nuclear Fuel and Decommissioning Trusts	485	772	-	11	1,268
Total Assets	$ 1,074	$ 3,572	$ 92	$ (2,108)	$ 2,630
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (e)	$ 56	$ 2,508	$ 25	$ (2,321)	$ 268
Cash Flow Hedges (e)	2	39	-	(13)	28
Total Risk Management Liabilities	$ 58	$ 2,547	$ 25	$ (2,334)	$ 296

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents					
Cash and Cash Equivalents (a)	$ 304	$ -	$ -	$ 60	$ 364
Debt Securities (b)	-	47	-	-	47
Total Cash and Cash Equivalents	304	47	-	60	411
Other Temporary Investments					
Cash and Cash Equivalents (a)	217	-	-	26	243
Debt Securities (c)	56	-	-	-	56
Equity Securities (d)	28	-	-	-	28
Total Other Temporary Investments	301	-	-	26	327
Risk Management Assets					
Risk Management Contracts (e)	61	2,413	86	(2,022)	538
Cash Flow Hedges (e)	6	32	-	(4)	34
Dedesignated Risk Management Contracts (f)	-	-	-	39	39
Total Risk Management Assets	67	2,445	86	(1,987)	611
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (g)	-	6	-	12	18
Debt Securities (h)	-	773	-	-	773
Equity Securities (d)	469	-	-	-	469
Total Spent Nuclear Fuel and Decommissioning Trusts	469	779	-	12	1,260
Total Assets	$ 1,141	$ 3,271	$ 86	$ (1,889)	$ 2,609
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (e)	$ 77	$ 2,213	$ 37	$ (2,054)	$ 273
Cash Flow Hedges (e)	1	34	-	(4)	31
Total Risk Management Liabilities	$ 78	$ 2,247	$ 37	$ (2,058)	$ 304

(a) Amounts in “Other” column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.

(b) Amount represents commercial paper investments with maturities of less than ninety days.

(c) Amounts represent debt-based mutual funds.

(d) Amount represents publicly traded equity securities and equity-based mutual funds.

(e) Amounts in “Other” column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(f) “Dedesignated Risk Management Contracts” are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into Utility Operations Revenues over the remaining life of the contracts.

(g) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(h) Amounts represent corporate, municipal and treasury bonds.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended June 30, 2009	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of April 1, 2009	$ 86	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(15)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	7	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	-	-
Transfers in and/or out of Level 3 (c)	(29)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	18	-	-
Balance as of June 30, 2009	$ 67	$ -	$ -

Six Months Ended June 30, 2009	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2009	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(20)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	40	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	-	-
Transfers in and/or out of Level 3 (c)	(25)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	23	-	-
Balance as of June 30, 2009	$ 67	$ -	$ -

Three Months Ended June 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of April 1, 2008	$ 49	$ 22	$ 17
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(2)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(1)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	(22)	(17)
Transfers in and/or out of Level 3 (c)	(8)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(46)	-	-
Balance as of June 30, 2008	$ (8)	$ -	$ -

Six Months Ended June 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2008	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(2)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(3)	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	(118)	(17)
Transfers in and/or out of Level 3 (c)	(1)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(51)	-	-
Balance as of June 30, 2008	$ (8)	$ -	$ -

(a) Included in revenues on our Condensed Consolidated Statements of Income.
(b) Includes principal amount of securities settled during the period.
(c) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

10. 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 tax expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

We are no longer subject to U.S. federal examination for years before 2000. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

Federal Tax Legislation

The American Recovery and Reinvestment Act of 2009 was signed into law by the President in February 2009. It provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions are not expected to have a material impact on net income or financial condition. However, we forecast the bonus depreciation provision could provide a significant favorable cash flow benefit in 2009.

11. FINANCING ACTIVITIES

Common Stock

In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion, which was primarily used to repay cash drawn under our credit facilities in the second quarter of 2009.

Long-term Debt

Type of Debt	June 30, 2009	December 31, 2008
	(in millions)	
Senior Unsecured Notes	$ 11,820	$ 11,069
Pollution Control Bonds	2,080	1,946
Notes Payable	146	233
Securitization Bonds	2,051	2,132
Junior Subordinated Debentures	315	315
Spent Nuclear Fuel Obligation (a)	264	264
Other Long-term Debt	88	88
Unamortized Discount (net)	(68)	(64)
Total Long-term Debt Outstanding	16,696	15,983
Less Portion Due Within One Year	1,346	447
Long-term Portion	$ 15,350	$ 15,536

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation to 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 $304 million and $301 million at June 30, 2009 and December 31, 2008, 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 2009 are shown in the tables below.

Company	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in millions)	(%)	
Issuances:				
APCo	Senior Unsecured Notes	$ 350	7.95	2020
I&M	Senior Unsecured Notes	475	7.00	2019
I&M	Pollution Control Bonds	50	6.25	2025
I&M	Pollution Control Bonds	50	6.25	2025
PSO	Pollution Control Bonds	34	5.25	2014
Non-Registrant:				
KPCo	Senior Unsecured Notes	40	7.25	2021
KPCo	Senior Unsecured Notes	30	8.03	2029
KPCo	Senior Unsecured Notes	60	8.13	2039
Total Issuances		$ 1,089 (a)		

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

(a) Amount indicated on statement of cash flows of $1,075 million is net of issuance costs and premium or discount.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Senior Unsecured Notes	$ 150	6.60	2009
OPCo	Notes Payable	1	6.27	2009
OPCo	Notes Payable	7	7.21	2009
OPCo	Notes Payable	70	7.49	2009
PSO	Senior Unsecured Notes	50	4.70	2009
SWEPCo	Notes Payable	2	4.47	2011
Non-Registrant:				
AEP Subsidiaries	Notes Payable	3	Variable	2017
AEP Subsidiaries	Notes Payable	4	5.88	2011
AEGCo	Senior Unsecured Notes	4	6.33	2037
TCC	Securitization Bonds	31	5.56	2010
TCC	Securitization Bonds	50	4.98	2010
Total Retirements and Principal Payments		$ 372		

In July 2009, TCC issued $101 million of 6.3% Pollution Control Bonds due in 2029.

During 2008, we chose to begin eliminating our auction-rate debt position due to market conditions. As of June 30, 2009, $272 million of our auction-rate tax-exempt long-term debt, with rates ranging between 1.122% and 13%, remained outstanding with rates reset every 35 days. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. As of June 30, 2009, $218 million of the $272 million of outstanding auction-rate debt relates to JMG. Interest rates on this debt are at the contractual maximum rate of 13%. We were unable to refinance this debt without JMG's consent. We sought approval from the PUCO to terminate the JMG relationship and received the approval in June 2009. In July 2009, we purchased the outstanding equity ownership of JMG for $28 million. We plan to refinance the related outstanding debt as market conditions permit.

As of June 30, 2009, trustees held, on our behalf, $195 million of our remaining reacquired auction-rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

Dividend Restrictions

We have the option to defer interest payments on the AEP Junior Subordinated Debentures issued in March 2008 for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our net income, cash flows, financial condition or limit any dividend payments in the foreseeable future.

Short-term Debt

Our outstanding short-term debt is as follows:

	June 30, 2009		December 31, 2008	
	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
Type of Debt	**(in thousands)**		**(in thousands)**	
Line of Credit – AEP	$ 219,000 (b)	0.79% (c)	$ 1,969,000	2.28% (c)
Line of Credit – Sabine Mining Company (d)	14,872	1.74%	7,172	1.54%
Commercial Paper – AEP	316,263	0.67%	-	-
Commercial Paper – JMG (e)	11,500	1.25%	-	-
Total	$ 561,635		$ 1,976,172	

(a) Weighted average rate.
(b) Paid $1.75 billion primarily with proceeds from the April 2009 equity issuance. Paid remaining $219 million in July 2009.
(c) Rate based on LIBOR.
(d) Sabine Mining Company is consolidated under FIN 46R. This line of credit does not reduce available liquidity under AEP's credit facilities.
(e) This commercial paper was used to pay down debt in the second quarter of 2009 and matured on July 1, 2009. This commercial paper does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

As of June 30, 2009, we have credit facilities totaling $3 billion to support our commercial paper program. The facilities are structured as two $1.5 billion credit facilities of which $750 million may be issued under each credit facility as letters of credit.

We have a $627 million 3-year credit agreement. Under the facility, we may issue letters of credit. As of June 30, 2009, $372 million of letters of credit were issued by subsidiaries under the $627 million 3-year agreement to support variable rate Pollution Control Bonds. We had a $350 million 364-day credit agreement that expired in April 2009.

Sales of Receivables

In July 2009, we renewed and increased our sale of receivables agreement. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables. This agreement will expire in July 2010.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Net Income
(in millions)

Second Quarter of 2008		$ 26
Changes in Gross Margin:		
Retail Margins	66	
Off-system Sales	(48)	
Other	(1)	
Total Change in Gross Margin		17
Total Expenses and Other:		
Other Operation and Maintenance	8	
Depreciation and Amortization	(3)	
Carrying Costs Income	(12)	
Other Income	(3)	
Interest Expense	(4)	
Total Expenses and Other		(14)
Second Quarter of 2009		$ 29

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 $66 million primarily due to the following:
  - A $38 million increase in rate relief primarily due to the impact of the Virginia base rate order issued in October 2008, an increase in the recovery of E&R costs in Virginia and an increase in the recovery of construction financing costs in West Virginia.
  - A $37 million increase due to a decrease in sharing of off-system sales margins with customers in Virginia and West Virginia.
  - A $6 million increase due to new rates effective January 2009 for a power supply contract with KGPCo.

  These increases were partially offset by:
  - A $14 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
  - An $8 million decrease in industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in APCo's service territory.
- Margins from Off-system Sales decreased $48 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.

Total Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $8 million primarily due to a $6 million regulatory asset recorded in June 2009 for the deferral of transmission costs. See "Virginia Rate Matters – Rate Adjustment Clauses" section of Note 3.
- Depreciation and Amortization expenses increased $3 million primarily due to a greater depreciation base resulting from asset improvements.
- Carrying Costs Income decreased $12 million due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Interest Expense increased $4 million primarily due to an increase in long-term debt issuances.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Net Income
(in millions)

Six Months Ended June 30, 2008		$ 82
Changes in Gross Margin:		
Retail Margins	153	
Off-system Sales	(95)	
Total Change in Gross Margin		58
Total Expenses and Other:		
Other Operation and Maintenance	20	
Depreciation and Amortization	(10)	
Carrying Costs Income	(17)	
Other Income	(5)	
Interest Expense	(10)	
Total Expenses and Other		(22)
Income Tax Expense		(14)
Six Months Ended June 30, 2009		$ 104

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 $153 million primarily due to the following:
  - A $91 million increase in rate relief primarily due to the impact of the Virginia base rate order issued in October 2008, an increase in the recovery of E&R costs in Virginia and an increase in the recovery of construction financing costs in West Virginia.
  - A $70 million increase due to a decrease in sharing of off-system sales margins with customers in Virginia and West Virginia.
  - A $13 million increase due to new rates effective January 2009 for a power supply contract with KGPCo.

  These increases were partially offset by:
  - A $28 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
  - A $10 million decrease in industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in APCo's service territory.
- Margins from Off-system Sales decreased $95 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $20 million due to an $11 million decrease in employee-related expenses and generation plant maintenance. In addition, a $6 million regulatory asset was recorded in June 2009 for the deferral of transmission costs. See "Virginia Rate Matters – Rate Adjustment Clauses" section of Note 3.
- Depreciation and Amortization expenses increased $10 million primarily due to a greater depreciation base resulting from asset improvements and the amortization of carrying charges and depreciation expenses that are being collected through the Virginia E&R surcharges.
- Carrying Costs Income decreased $17 million due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Interest Expense increased $10 million primarily due to an increase in long-term debt issuances.
- Income Tax Expense increased $14 million primarily due to an increase in pretax book income, partially offset by a decrease in state income taxes.

Financial Condition

Credit Ratings

APCo's credit ratings as of June 30, 2009 were as follows:

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

S&P has APCo on stable outlook, while Fitch has APCo on negative outlook. In February 2009, Moody's changed its rating outlook for APCo from negative to stable. If APCo receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the six months ended June 30, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,996	$ 2,195
Cash Flows from (Used for):		
Operating Activities	(90,383)	140,378
Investing Activities	(313,971)	(296,095)
Financing Activities	404,159	155,398
Net Decrease in Cash and Cash Equivalents	(195)	(319)
Cash and Cash Equivalents at End of Period	$ 1,801	$ 1,876

Operating Activities

Net Cash Flows Used for Operating Activities were $90 million in 2009. APCo produced Net Income of $104 million during the period and had noncash expense items of $134 million for Depreciation and Amortization and $135 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The $138 million change in Fuel Over/Under-Recovery, Net resulted in a net under-recovery of fuel cost in both Virginia and West Virginia. The $136 million outflow from Accounts Payable was primarily due to APCo's provision for revenue refund of $77 million which was paid in the first quarter 2009 to the AEP West companies as part of the FERC's order on the SIA. The $93 million outflow from Fuel, Materials and Supplies was primarily due to an increase in coal inventory. The $87 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The $79 million outflow from Accrued Taxes, Net was primarily due to increased accruals related to federal income taxes.

Net Cash Flows from Operating Activities were $140 million in 2008. APCo produced Net Income of $82 million during the period and had noncash expense items of $124 million for Depreciation and Amortization and $72 million for Deferred Income Taxes, partially offset by $27 million in Carrying Costs Income. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The $77 million change in Fuel Over/Under-Recovery, Net resulted in a net under-recovery of fuel cost in both Virginia and West Virginia due to higher fuel costs. The $41 million inflow from the change in Accounts Payable was primarily due to an increase in fuel costs.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $314 million and $296 million, respectively. Construction Expenditures were $328 million and $312 million in 2009 and 2008, respectively, primarily related to transmission and distribution service reliability projects, as well as environmental upgrades for both periods. Environmental upgrades include the installation of selective catalytic reduction equipment on APCo's plants and flue gas desulfurization projects at the Amos and Mountaineer Plants. APCo forecasts approximately $368 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows from Financing Activities were $404 million in 2009. APCo received capital contributions from the Parent of $250 million in the second quarter of 2009. APCo issued $350 million of Senior Unsecured Notes in March 2009. APCo retired $150 million of Senior Unsecured Notes in May 2009.

Net Cash Flows from Financing Activities were $155 million in 2008. APCo received capital contributions from the Parent of $125 million. APCo issued $500 million of Senior Unsecured Notes in March 2008 and $125 million of Pollution Control Bonds in June 2008. These increases were partially offset by the retirement of $213 million of Pollution Control Bonds and the retirement of $200 million of Senior Unsecured Notes in the second quarter of 2008. In addition, APCo had a net decrease of $171 million in borrowings from the Utility Money Pool.

Financing Activity

Long-term debt issuances, retirements and principal payments made during the first six months of 2009 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 350,000	7.95	2020

Retirements and Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 150,000	6.60	2009
Land Note	8	13.718	2026

Liquidity

Although the financial markets remain volatile at both a global and domestic level, APCo issued $350 million of Senior Unsecured Notes during the first six months of 2009. The uncertainties in the capital markets could have significant implications on APCo since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on APCo's operations and ability to issue debt at reasonable interest rates.

APCo participates in the Utility Money Pool, which provides access to AEP's liquidity. APCo will rely upon cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2008 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, 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 regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2008 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 beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 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 2008 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 beginning on page I-1 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 in APCo's Condensed Consolidated Balance Sheet as of June 30, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
June 30, 2009
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 82,398	$ 3,752	$ -	$ (5,587)	$ 80,563
Noncurrent Assets	61,751	1,110	-	(5,468)	57,393
Total MTM Derivative Contract Assets	144,149	4,862	-	(11,055)	137,956
Current Liabilities	48,726	1,326	2,698	(18,571)	34,179
Noncurrent Liabilities	34,853	1,020	1,270	(14,509)	22,634
Total MTM Derivative Contract Liabilities	83,579	2,346	3,968	(33,080)	56,813
Total MTM Derivative Contract Net Assets (Liabilities)	$ 60,570	$ 2,516	$ (3,968)	$ 22,025	$ 81,143

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$ 56,936
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(19,473)
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	(183)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(464)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	23,754
Total MTM Risk Management Contract Net Assets	60,570
Cash Flow Hedge Contracts	2,516
DETM Assignment (d)	(3,968)
Collateral Deposits	22,025
Ending Net Risk Management Assets at June 30, 2009	$ 81,143

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(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.
(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

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

The following table presents 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 (Liabilities)
June 30, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (1,052)	$ (29)	$ 1	$ -	$ -	$ -	$ (1,080)
Level 2 (b)	14,474	14,445	6,184	182	1,130	404	36,819
Level 3 (c)	4,458	6,383	2,140	940	(21)	-	13,900
Total	17,880	20,799	8,325	1,122	1,109	404	49,639
Dedesignated Risk Management Contracts (d)	2,481	4,862	1,894	1,694	-	-	10,931
Total MTM Risk Management Contract Net Assets	$ 20,361	$ 25,661	$ 10,219	$ 2,816	$ 1,109	$ 404	$ 60,570

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1 and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.
(d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contracts.

Credit Risk

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

See Note 8 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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, 2009, a near term typical change in commodity prices is not expected to have a material effect on net income, 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, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$357	$699	$353	$151	$176	$1,096	$396	$161

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management's back-testing results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes APCo's VaR calculation is conservative.

As APCo's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand APCo's exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which APCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on APCo's debt outstanding as of June 30, 2009, the estimated EaR on APCo's debt portfolio for the following twelve months was $6 million.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended 2009	Three Months Ended 2008	Six Months Ended 2009	Six Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 572,027	$ 566,089	$ 1,299,986	$ 1,207,546
Sales to AEP Affiliates	62,038	97,508	118,269	187,598
Other Revenues	2,047	3,800	3,886	7,280
TOTAL REVENUES	636,112	667,397	1,422,141	1,402,424
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	118,891	159,237	262,572	333,067
Purchased Electricity for Resale	59,631	52,931	135,447	96,130
Purchased Electricity from AEP Affiliates	171,064	186,243	368,188	375,838
Other Operation	63,537	68,415	129,039	143,946
Maintenance	49,478	52,235	105,388	110,079
Depreciation and Amortization	64,148	61,592	134,143	124,164
Taxes Other Than Income Taxes	23,796	24,104	47,899	48,095
TOTAL EXPENSES	550,545	604,757	1,182,676	1,231,319
OPERATING INCOME	85,567	62,640	239,465	171,105
Other Income (Expense):				
Interest Income	395	2,827	777	5,596
Carrying Costs Income	5,791	17,411	9,874	26,997
Allowance for Equity Funds Used During Construction	1,184	2,652	3,837	4,148
Interest Expense	(51,457)	(47,119)	(101,162)	(91,259)
INCOME BEFORE INCOME TAX EXPENSE	41,480	38,411	152,791	116,587
Income Tax Expense	12,310	12,129	49,214	34,992
NET INCOME	29,170	26,282	103,577	81,595
Preferred Stock Dividend Requirements Including Capital Stock Expense	225	238	450	476
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 28,945	$ 26,044	$ 103,127	$ 81,119

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	$ 260,458	$ 1,025,149	$ 831,612	$ (35,187)	$ 2,082,032
EITF 06-10 Adoption, Net of Tax of $1,175			(2,181)		(2,181)
SFAS 157 Adoption, Net of Tax of $154			(286)		(286)
Capital Contribution from Parent		125,000			125,000
Preferred Stock Dividends			(399)		(399)
Capital Stock Expense		77	(77)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,204,166
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $10,085				(18,729)	(18,729)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $897				1,666	1,666
NET INCOME			81,595		81,595
TOTAL COMPREHENSIVE INCOME					64,532
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2008	$ 260,458	$ 1,150,226	$ 910,264	$ (52,250)	$ 2,268,698
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 260,458	$ 1,225,292	$ 951,066	$ (60,225)	$ 2,376,591
Capital Contribution from Parent		250,000			250,000
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(399)		(399)
Capital Stock Expense		51	(51)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,606,192
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $217				403	403
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,034				1,920	1,920
NET INCOME			103,577		103,577
TOTAL COMPREHENSIVE INCOME					105,900
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009	$ 260,458	$ 1,475,343	$ 1,034,193	$ (57,902)	$ 2,712,092

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,801	$ 1,996
Accounts Receivable:		
Customers	149,544	175,709
Affiliated Companies	69,952	110,982
Accrued Unbilled Revenues	35,511	55,733
Miscellaneous	1,040	498
Allowance for Uncollectible Accounts	(6,141)	(6,176)
Total Accounts Receivable	249,906	336,746
Fuel	218,208	131,239
Materials and Supplies	82,595	76,260
Risk Management Assets	80,563	65,140
Accrued Tax Benefits	87,254	15,599
Regulatory Asset for Under-Recovered Fuel Costs	303,623	165,906
Prepayments and Other Current Assets	62,052	45,657
TOTAL CURRENT ASSETS	1,086,002	838,543
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,206,882	3,708,850
Transmission	1,791,345	1,754,192
Distribution	2,571,796	2,499,974
Other Property, Plant and Equipment	355,400	358,873
Construction Work in Progress	645,739	1,106,032
Total Property, Plant and Equipment	9,571,162	9,427,921
Accumulated Depreciation and Amortization	2,717,946	2,675,784
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,853,216	6,752,137
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,033,039	999,061
Long-term Risk Management Assets	57,393	51,095
Deferred Charges and Other Noncurrent Assets	110,605	121,828
TOTAL OTHER NONCURRENT ASSETS	1,201,037	1,171,984
TOTAL ASSETS	$ 9,140,255	$ 8,762,664

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 175,376	$ 194,888
Accounts Payable:		
General	210,147	358,081
Affiliated Companies	102,248	206,813
Long-term Debt Due Within One Year – Nonaffiliated	200,018	150,017
Long-term Debt Due Within One Year – Affiliated	100,000	-
Risk Management Liabilities	34,179	30,620
Customer Deposits	56,976	54,086
Deferred Income Taxes	137,159	-
Accrued Taxes	58,432	65,550
Accrued Interest	52,456	47,804
Other Current Liabilities	78,598	113,655
TOTAL CURRENT LIABILITIES	1,205,589	1,221,514
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,071,770	2,924,495
Long-term Debt – Affiliated	-	100,000
Long-term Risk Management Liabilities	22,634	26,388
Deferred Income Taxes	1,137,275	1,131,164
Regulatory Liabilities and Deferred Investment Tax Credits	528,204	521,508
Employee Benefits and Pension Obligations	327,766	331,000
Deferred Credits and Other Noncurrent Liabilities	117,173	112,252
TOTAL NONCURRENT LIABILITIES	5,204,822	5,146,807
TOTAL LIABILITIES	6,410,411	6,368,321
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,752	17,752
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	1,475,343	1,225,292
Retained Earnings	1,034,193	951,066
Accumulated Other Comprehensive Income (Loss)	(57,902)	(60,225)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,712,092	2,376,591
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 9,140,255	$ 8,762,664

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 103,577	$ 81,595
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	134,143	124,164
Deferred Income Taxes	135,034	71,728
Carrying Costs Income	(9,874)	(26,997)
Allowance for Equity Funds Used During Construction	(3,837)	(4,148)
Mark-to-Market of Risk Management Contracts	(23,490)	17,298
Change in Other Noncurrent Assets	(24,202)	(14,006)
Change in Other Noncurrent Liabilities	13,786	(20,038)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	86,840	2,583
Fuel, Materials and Supplies	(93,304)	(5,495)
Accounts Payable	(136,330)	40,905
Accrued Taxes, Net	(78,773)	(31,213)
Fuel Over/Under-Recovery, Net	(137,717)	(77,036)
Other Current Assets	(29,341)	(14,225)
Other Current Liabilities	(26,895)	(4,737)
Net Cash Flows from (Used for) Operating Activities	(90,383)	140,378
INVESTING ACTIVITIES		
Construction Expenditures	(327,982)	(311,550)
Change in Other Cash Deposits	235	(15)
Acquisitions of Assets	(876)	-
Proceeds from Sales of Assets	14,652	15,470
Net Cash Flows Used for Investing Activities	(313,971)	(296,095)
FINANCING ACTIVITIES		
Capital Contribution from Parent	250,000	125,000
Issuance of Long-term Debt – Nonaffiliated	345,666	617,111
Change in Advances from Affiliates, Net	(19,512)	(171,455)
Retirement of Long-term Debt – Nonaffiliated	(150,008)	(412,782)
Principal Payments for Capital Lease Obligations	(1,669)	(2,077)
Dividends Paid on Common Stock	(20,000)	-
Dividends Paid on Cumulative Preferred Stock	(399)	(399)
Other Financing Activities	81	-
Net Cash Flows from Financing Activities	404,159	155,398
Net Decrease in Cash and Cash Equivalents	(195)	(319)
Cash and Cash Equivalents at Beginning of Period	1,996	2,195
Cash and Cash Equivalents at End of Period	$ 1,801	$ 1,876
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 114,983	$ 86,873
Net Cash Received for Income Taxes	(2,644)	(10,708)
Noncash Acquisitions Under Capital Leases	526	1,014
Construction Expenditures Included in Accounts Payable at June 30,	69,300	98,958

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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. The footnotes begin on page H-1.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Net Income
(in millions)

Second Quarter of 2008		$ 56
Changes in Gross Margin:		
Retail Margins	48	
Off-system Sales	(28)	
Other	(1)	
Total Change in Gross Margin		19
Total Expenses and Other:		
Other Operation and Maintenance	22	
Depreciation and Amortization	13	
Taxes Other Than Income Taxes	(2)	
Other Income	(1)	
Interest Expense	(4)	
Total Expenses and Other		28
Income Tax Expense		(19)
Second Quarter of 2009		$ 84

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 $48 million primarily due to:
  - A $38 million increase related to the implementation of higher rates set by the Ohio ESP.
  - A $17 million increase in fuel margins due to the deferral of fuel costs in 2009. The PUCO's March 2009 approval of CSPCo's ESP allows for the recovery of fuel and related costs incurred since January 1, 2009. See "Ohio Electric Security Plan Filings" section of Note 3.

  These increases were partially offset by:
  - A $12 million decrease related to the cessation of Restructuring Transition Charge (RTC) revenues with the implementation of rates under the Ohio ESP.
  - An $8 million decrease in industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in CSPCo's service territory.
- Margins from Off-system Sales decreased $28 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $22 million primarily due to:
  - An $8 million decrease in expenses related to CSPCo's Unit Power Agreement for AEGCo's Lawrenceburg Plant. In 2008, these expenses were recorded in Other Operation and Maintenance. With the March 2009 ESP order, approval was granted to record these costs in purchased power and recover through the FAC.
  - A $5 million decrease in boiler plant removal and maintenance expenses primarily related to work performed at the Conesville Plant in 2008.
  - A $4 million decrease in recoverable PJM expenses.
- Depreciation and Amortization decreased $13 million primarily due to the completed amortization of transition regulatory assets in December 2008.

- Interest Expense increased $4 million due to adjustments recorded in 2008 related to tax reserves.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Net Income
(in millions)

Six Months Ended June 30, 2008		$ 133
Changes in Gross Margin:		
Retail Margins	29	
Off-system Sales	(51)	
Other	(1)	
Total Change in Gross Margin		(23)
Total Expenses and Other:		
Other Operation and Maintenance	11	
Depreciation and Amortization	27	
Taxes Other Than Income Taxes	(3)	
Other Income	(4)	
Interest Expense	(5)	
Total Expenses and Other		26
Income Tax Expense		(3)
Six Months Ended June 30, 2009		$ 133

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 increased $29 million primarily due to:
  - A $43 million increase related to the implementation of higher rates set by the Ohio ESP.
  - A $22 million increase in fuel margins due to the deferral of fuel costs in 2009. The PUCO's March 2009 approval of CSPCo's ESP allows for the recovery of fuel and related costs incurred since January 1, 2009. See "Ohio Electric Security Plan Filings" section of Note 3.

  These increases were partially offset by:
  - A $26 million decrease as a result of Restructuring Transition Charge (RTC) revenues. The PUCO allowed CSPCo to continue collecting the RTC pending the implementation of the new ESP tariffs which did not occur until March 30, 2009. During the first quarter of 2009, these revenues were offset in fuel under-recovery. In 2008, RTC revenues were recorded but were offset through the amortization of the transition regulatory assets as discussed below. With the implementation of the Ohio ESP, RTC revenues ended. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $5 million decrease in retail sales. Industrial sales decreased $12 million due to reduced operating levels and suspended operations by certain large industrial customers in CSPCo's service territory. This decrease was partially offset by an $8 million increase in residential sales.
- Margins from Off-system Sales decreased $51 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $11 million primarily due to:
  - A $17 million decrease in expenses related to CSPCo's Unit Power Agreement for AEGCo's Lawrenceburg Plant. In 2008, these expenses were recorded in Other Operation and Maintenance. With the March 2009 ESP order, approval was granted to record these costs in purchased power and recover through the FAC.
  - A $2 million decrease in net allocated transmission expenses related to the Transmission Agreement.
  - A $2 million decrease in boiler plant maintenance expenses primarily related to work performed at the Conesville Plant in 2008.
  - A $2 million decrease in maintenance expenses for overhead transmission lines.

  These decreases were partially offset by:
  - A $10 million increase in overhead line expenses primarily due to ice and wind storms in the first quarter of 2009 and increased vegetation management activities.
  - A $7 million increase related to an obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of CSPCo's ESP. See "Ohio Electric Security Plan Filings" section of Note 3.
- Depreciation and Amortization decreased $27 million primarily due to the completed amortization of transition regulatory assets in December 2008.
- Taxes Other Than Income Taxes increased $3 million due to increases in property taxes.
- Other Income decreased $4 million primarily due to interest income recorded in 2008 on expected federal tax refund related to Simple Service Cost Method.
- Interest Expense increased $5 million primarily due to an increase in long-term borrowings and adjustments recorded in 2008 related to tax reserves, which were partially offset by an increase in the debt component of AFUDC.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income and state income taxes and changes in certain book/tax differences.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2008 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 beginning on page I-1 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 for disclosures about risk management activities.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which CSPCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on CSPCo's debt outstanding as of June 30, 2009, the estimated EaR on CSPCo's debt portfolio for the following twelve months was $989 thousand.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended 2009	Three Months Ended 2008	Six Months Ended 2009	Six Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 488,193	$ 500,056	$ 949,115	$ 1,005,380
Sales to AEP Affiliates	19,165	47,413	29,371	82,521
Other Revenues	518	1,478	1,126	2,695
TOTAL REVENUES	507,876	548,947	979,612	1,090,596
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	63,476	86,253	134,420	171,380
Purchased Electricity for Resale	22,422	45,010	52,260	87,196
Purchased Electricity from AEP Affiliates	96,068	110,578	189,160	204,682
Other Operation	65,555	84,955	141,643	158,021
Maintenance	31,618	34,435	62,632	57,666
Depreciation and Amortization	34,626	47,693	69,571	96,295
Taxes Other Than Income Taxes	43,145	40,989	88,427	85,545
TOTAL EXPENSES	356,910	449,913	738,113	860,785
OPERATING INCOME	150,966	99,034	241,499	229,811
Other Income (Expense):				
Interest Income	234	1,603	474	3,942
Carrying Costs Income	1,721	1,538	3,410	3,304
Allowance for Equity Funds Used During Construction	585	565	1,885	1,420
Interest Expense	(21,076)	(17,246)	(41,869)	(36,485)
INCOME BEFORE INCOME TAX EXPENSE	132,430	85,494	205,399	201,992
Income Tax Expense	48,252	29,101	72,363	69,446
NET INCOME	84,178	56,393	133,036	132,546
Capital Stock Expense	40	40	79	79
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 84,138	$ 56,353	$ 132,957	$ 132,467

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	$ 41,026	$ 580,349	$ 561,696	$ (18,794)	$ 1,164,277
EITF 06-10 Adoption, Net of Tax of $589			(1,095)		(1,095)
SFAS 157 Adoption, Net of Tax of $170			(316)		(316)
Common Stock Dividends			(62,500)		(62,500)
Capital Stock Expense		79	(79)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,100,366
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $5,090				(9,451)	(9,451)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $304				564	564
NET INCOME			132,546		132,546
TOTAL COMPREHENSIVE INCOME					123,659
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2008	$ 41,026	$ 580,428	$ 630,252	$ (27,681)	$ 1,224,025
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 41,026	$ 580,506	$ 674,758	$ (51,025)	$ 1,245,265
Common Stock Dividends			(100,000)		(100,000)
Capital Stock Expense		79	(79)		-
Noncash Dividend of Property to Parent			(8,123)		(8,123)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,137,142
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $184				(342)	(342)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $514				954	954
NET INCOME			133,036		133,036
TOTAL COMPREHENSIVE INCOME					133,648
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009	$ 41,026	$ 580,585	$ 699,592	$ (50,413)	$ 1,270,790

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,313	$ 1,063
Other Cash Deposits	21,225	32,300
Accounts Receivable:		
Customers	44,477	56,008
Affiliated Companies	15,378	44,235
Accrued Unbilled Revenues	19,287	18,359
Miscellaneous	5,147	11,546
Allowance for Uncollectible Accounts	(3,774)	(2,895)
Total Accounts Receivable	80,515	127,253
Fuel	66,275	42,075
Materials and Supplies	38,602	33,781
Emission Allowances	15,627	20,211
Risk Management Assets	42,398	35,984
Margin Deposits	23,204	13,613
Prepayments and Other Current Assets	13,752	27,880
TOTAL CURRENT ASSETS	302,911	334,160
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,356,628	2,326,056
Transmission	583,591	574,018
Distribution	1,680,596	1,625,000
Other Property, Plant and Equipment	200,914	211,088
Construction Work in Progress	419,899	394,918
Total Property, Plant and Equipment	5,241,628	5,131,080
Accumulated Depreciation and Amortization	1,825,274	1,781,866
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,416,354	3,349,214
OTHER NONCURRENT ASSETS		
Regulatory Assets	331,579	298,357
Long-term Risk Management Assets	30,381	28,461
Deferred Charges and Other Noncurrent Assets	89,602	125,814
TOTAL OTHER NONCURRENT ASSETS	451,562	452,632
TOTAL ASSETS	$ 4,170,827	$ 4,136,006

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 162,659	$ 74,865
Accounts Payable:		
General	111,309	131,417
Affiliated Companies	51,071	120,420
Long-term Debt Due Within One Year – Affiliated	100,000	-
Risk Management Liabilities	17,949	16,490
Customer Deposits	31,535	30,145
Accrued Taxes	124,752	185,293
Other Current Liabilities	101,911	82,678
TOTAL CURRENT LIABILITIES	701,186	641,308
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,343,799	1,343,594
Long-term Debt – Affiliated	-	100,000
Long-term Risk Management Liabilities	11,984	14,774
Deferred Income Taxes	476,204	435,773
Regulatory Liabilities and Deferred Investment Tax Credits	172,371	161,102
Employee Benefits and Pension Obligations	144,746	148,123
Deferred Credits and Other Noncurrent Liabilities	49,747	46,067
TOTAL NONCURRENT LIABILITIES	2,198,851	2,249,433
TOTAL LIABILITIES	2,900,037	2,890,741
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	580,585	580,506
Retained Earnings	699,592	674,758
Accumulated Other Comprehensive Income (Loss)	(50,413)	(51,025)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,270,790	1,245,265
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 4,170,827	$ 4,136,006

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 133,036	$ 132,546
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	69,571	96,295
Deferred Income Taxes	60,104	9,670
Carrying Costs Income	(3,410)	(3,304)
Allowance for Equity Funds Used During Construction	(1,885)	(1,420)
Mark-to-Market of Risk Management Contracts	(10,671)	10,859
Deferred Property Taxes	44,075	43,745
Fuel Over/Under-Recovery, Net	(33,963)	-
Change in Other Noncurrent Assets	(10,738)	(19,046)
Change in Other Noncurrent Liabilities	20,003	(2,759)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	46,738	(18,134)
Fuel, Materials and Supplies	(29,021)	(1,912)
Accounts Payable	(84,284)	8,747
Customer Deposits	1,390	2,095
Accrued Taxes, Net	(60,756)	(25,530)
Other Current Assets	3,600	(2,160)
Other Current Liabilities	5,772	(13,657)
Net Cash Flows from Operating Activities	149,561	216,035
INVESTING ACTIVITIES		
Construction Expenditures	(147,128)	(191,668)
Change in Other Cash Deposits	11,075	16,785
Change in Advances to Affiliates, Net	-	(25,199)
Acquisitions of Assets	(184)	-
Proceeds from Sales of Assets	465	700
Net Cash Flows Used for Investing Activities	(135,772)	(199,382)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	346,934
Change in Advances from Affiliates, Net	87,794	(95,199)
Retirement of Long-term Debt – Nonaffiliated	-	(204,245)
Principal Payments for Capital Lease Obligations	(1,333)	(1,441)
Dividends Paid on Common Stock	(100,000)	(62,500)
Net Cash Flows Used for Financing Activities	(13,539)	(16,451)
Net Increase in Cash and Cash Equivalents	250	202
Cash and Cash Equivalents at Beginning of Period	1,063	1,389
Cash and Cash Equivalents at End of Period	$ 1,313	$ 1,591
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 53,045	$ 38,531
Net Cash Paid for Income Taxes	1,239	22,307
Noncash Acquisitions Under Capital Leases	565	1,228
Construction Expenditures Included in Accounts Payable at June 30,	42,894	62,157
Noncash Dividend of Property to Parent	8,123	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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. The footnotes begin on page H-1.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

Results of Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Net Income
(in millions)

Second Quarter of 2008		$ 50
Changes in Gross Margin:		
Retail Margins	(21)	
FERC Municipals and Cooperatives	5	
Off-system Sales	(28)	
Other	39	
Total Change in Gross Margin		(5)
Total Expenses and Other:		
Other Operation and Maintenance	11	
Depreciation and Amortization	(2)	
Taxes Other Than Income Taxes	2	
Other Income	2	
Interest Expense	(9)	
Total Expenses and Other		4
Second Quarter of 2009		$ 49

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 $21 million primarily due to the following:
  - A $16 million decline due to a 20% decrease in industrial sales resulting from reduced operating levels and suspended operations by certain large industrial customers.
  - Lower fuel recoveries reflecting $20 million of insurance recoveries allocated to customers under fuel clauses.

  These decreases were partially offset by:
  - A $13 million increase in capacity revenue reflecting MLR changes.
- FERC Municipals and Cooperatives margins increased $5 million due to higher revenues under formula rate plans in 2009.
- Margins from Off-system Sales decreased $28 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.
- Other revenues increased $39 million primarily due to Cook Plant accidental outage insurance policy proceeds of $45 million. Of these insurance proceeds, $20 million were used to offset fuel costs in customer bills which are primarily included in Retail Margins. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. A decrease in River Transportation Division (RTD) revenues partially offset the insurance proceeds. RTD's related expenses which offset the RTD revenues are included in Other Operation on the Condensed Consolidated Statements of Income.

Total Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $11 million primarily due to a $5 million decline in operation and maintenance expenses for RTD caused by decreased barging activity in addition to a $3 million decline in accretion expense.
- Interest Expense increased $9 million primarily due to increased borrowings. In January 2009, I&M issued $475 million of 7% senior unsecured notes.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Net Income
(in millions)

Six Months Ended June 30, 2008		$ 105
Changes in Gross Margin:		
Retail Margins	(23)	
FERC Municipals and Cooperatives	4	
Off-system Sales	(56)	
Transmission Revenues	(1)	
Other	95	
Total Change in Gross Margin		19
Total Expenses and Other:		
Other Operation and Maintenance	26	
Depreciation and Amortization	(3)	
Taxes Other Than Income Taxes	1	
Other Income	4	
Interest Expense	(13)	
Total Expenses and Other		15
Income Tax Expense		(10)
Six Months Ended June 30, 2009		$ 129

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 $23 million primarily due to the following:
  - A $30 million decline due to a 20% decrease in industrial sales resulting from reduced operating levels and suspended operations by certain large industrial customers.
  - Lower fuel recoveries reflecting $40 million of Cook Plant accidental outage insurance recoveries allocated to customers under fuel clauses.

  These decreases were partially offset by:
  - A $21 million increase in capacity revenue reflecting MLR changes.
  - A $17 million increase from an Indiana rate settlement. See "Indiana Base Rate Filing" section of Note 3.
  - A $10 million favorable impact for lower PJM charges reflecting a decline in sales volume.
- FERC Municipals and Cooperatives margins increased $4 million due to higher revenues under formula rate plans in 2009.
- Margins from Off-system Sales decreased $56 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.
- Other revenues increased $95 million primarily due to Cook Plant accidental outage insurance policy proceeds of $99 million. Of the insurance proceeds, $40 million were used to offset fuel costs in customer bills which are primarily included in Retail Margins. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $26 million primarily due to lower nuclear and coal production, transmission and distribution costs and deferral of NSR and OPEB costs included in the rate settlement for recovery. See "Indiana Base Rate Filing" section of Note 3.
- Interest Expense increased $13 million primarily due to increased borrowings. In January 2009, I&M issued $475 million of 7% senior unsecured notes.
- Income Tax Expense increased $10 million primarily due to an increase in pretax book income, partially offset by a decrease in state income taxes.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of June 30, 2009, I&M recorded $54 million in Prepayments and Other Current Assets on the Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursements from NEIL for the cost incurred to date to repair the property damage. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In 2009, I&M recorded $99 million in revenues, including $9 million of revenues that were deferred at December 31, 2008, related to the accidental outage policy. In 2009, I&M applied $40 million of the accidental outage insurance proceeds to reduce customer bills. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2008 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 beginning on page I-1 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 for disclosures about risk management activities.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which I&M's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on I&M's debt outstanding as of June 30, 2009, the estimated EaR on I&M's debt portfolio for the following twelve months was $8.7 million.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended 2009	Three Months Ended 2008	Six Months Ended 2009	Six Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 400,347	$ 425,018	$ 822,274	$ 856,610
Sales to AEP Affiliates	57,385	83,927	117,371	160,439
Other Revenues – Affiliated	25,192	29,257	55,932	52,476
Other Revenues – Nonaffiliated	47,492	4,445	101,883	10,271
TOTAL REVENUES	530,416	542,647	1,097,460	1,079,796
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	108,202	108,496	211,162	209,737
Purchased Electricity for Resale	30,853	26,441	69,214	47,924
Purchased Electricity from AEP Affiliates	80,893	91,858	160,871	184,499
Other Operation	115,224	124,687	224,684	245,053
Maintenance	51,488	52,608	97,762	103,829
Depreciation and Amortization	33,629	31,757	66,374	63,479
Taxes Other Than Income Taxes	18,253	20,342	38,949	40,244
TOTAL EXPENSES	438,542	456,189	869,016	894,765
OPERATING INCOME	91,874	86,458	228,444	185,031
Other Income (Expense):				
Interest Income	974	1,904	3,517	2,733
Allowance for Equity Funds Used During Construction	2,783	128	4,338	1,008
Interest Expense	(26,173)	(17,146)	(49,704)	(36,348)
INCOME BEFORE INCOME TAX EXPENSE	69,458	71,344	186,595	152,424
Income Tax Expense	20,949	21,200	57,134	47,022
NET INCOME	48,509	50,144	129,461	105,402
Preferred Stock Dividend Requirements	85	85	170	170
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 48,424	$ 50,059	$ 129,291	$ 105,232

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	$ 56,584	$ 861,291	$ 483,499	$ (15,675)	$ 1,385,699
EITF 06-10 Adoption, Net of Tax of $753			(1,398)		(1,398)
Common Stock Dividends			(37,500)		(37,500)
Preferred Stock Dividends			(170)		(170)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,346,631
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,618				(8,577)	(8,577)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $118				220	220
NET INCOME			105,402		105,402
TOTAL COMPREHENSIVE INCOME					97,045
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2008	$ 56,584	$ 861,291	$ 549,833	$ (24,032)	$ 1,443,676
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 56,584	$ 861,291	$ 538,637	$ (21,694)	$ 1,434,818
Capital Contribution from Parent		120,000			120,000
Common Stock Dividends			(49,000)		(49,000)
Preferred Stock Dividends			(170)		(170)
Gain on Reacquired Preferred Stock		1			1
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,505,649
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $103				192	192
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $184				341	341
NET INCOME			129,461		129,461
TOTAL COMPREHENSIVE INCOME					129,994
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009	$ 56,584	$ 981,292	$ 618,928	$ (21,161)	$ 1,635,643

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 812	$ 728
Accounts Receivable:		
Customers	76,191	70,432
Affiliated Companies	84,849	94,205
Accrued Unbilled Revenues	12,446	19,260
Miscellaneous	1,976	1,010
Allowance for Uncollectible Accounts	(3,343)	(3,310)
Total Accounts Receivable	172,119	181,597
Fuel	70,060	67,138
Materials and Supplies	156,390	150,644
Risk Management Assets	41,711	35,012
Accrued Tax Benefits	32,591	3,523
Regulatory Asset for Under-Recovered Fuel Costs	28,143	33,066
Prepayments and Other Current Assets	93,205	63,210
TOTAL CURRENT ASSETS	595,031	534,918
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,562,756	3,534,188
Transmission	1,143,391	1,115,762
Distribution	1,337,501	1,297,482
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	797,462	703,287
Construction Work in Progress	267,862	249,020
Total Property, Plant and Equipment	7,108,972	6,899,739
Accumulated Depreciation, Depletion and Amortization	3,075,760	3,019,206
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,033,212	3,880,533
OTHER NONCURRENT ASSETS		
Regulatory Assets	493,402	455,132
Spent Nuclear Fuel and Decommissioning Trusts	1,268,442	1,259,533
Long-term Risk Management Assets	29,535	27,616
Deferred Charges and Other Noncurrent Assets	99,201	86,193
TOTAL OTHER NONCURRENT ASSETS	1,890,580	1,828,474
TOTAL ASSETS	$ 6,518,823	$ 6,243,925

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 2,350	$ 476,036
Accounts Payable:		
General	124,953	194,211
Affiliated Companies	62,600	117,589
Long-term Debt Due Within One Year – Affiliated	25,000	-
Risk Management Liabilities	17,698	16,079
Customer Deposits	28,088	26,809
Accrued Taxes	73,695	66,363
Accrued Interest	25,812	14,863
Obligations Under Capital Leases	30,990	43,512
Other Current Liabilities	83,317	126,297
TOTAL CURRENT LIABILITIES	474,503	1,081,759
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,950,138	1,377,914
Long-term Risk Management Liabilities	11,653	14,311
Deferred Income Taxes	523,154	412,264
Regulatory Liabilities and Deferred Investment Tax Credits	645,164	656,396
Asset Retirement Obligations	926,644	902,920
Deferred Credits and Other Noncurrent Liabilities	343,847	355,463
TOTAL NONCURRENT LIABILITIES	4,400,600	3,719,268
TOTAL LIABILITIES	4,875,103	4,801,027
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,077	8,080
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	981,292	861,291
Retained Earnings	618,928	538,637
Accumulated Other Comprehensive Income (Loss)	(21,161)	(21,694)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,635,643	1,434,818
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,518,823	$ 6,243,925

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 129,461	$ 105,402
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	66,374	63,479
Deferred Income Taxes	92,892	41,362
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(13,928)	(8,576)
Allowance for Equity Funds Used During Construction	(4,338)	(1,008)
Mark-to-Market of Risk Management Contracts	(10,602)	10,862
Amortization of Nuclear Fuel	24,718	45,312
Change in Other Noncurrent Assets	(8,727)	(9,103)
Change in Other Noncurrent Liabilities	26,606	19,847
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	9,383	6,194
Fuel, Materials and Supplies	(8,668)	1,094
Accounts Payable	(62,884)	449
Accrued Taxes, Net	(21,736)	6,607
Other Current Assets	(33,306)	(11,777)
Other Current Liabilities	(29,323)	(23,583)
Net Cash Flows from Operating Activities	155,922	246,561
INVESTING ACTIVITIES		
Construction Expenditures	(162,153)	(140,537)
Purchases of Investment Securities	(441,928)	(276,031)
Sales of Investment Securities	411,027	241,079
Acquisitions of Nuclear Fuel	(152,150)	(98,732)
Other Investing Activities	15,473	2,912
Net Cash Flows Used for Investing Activities	(329,731)	(271,309)
FINANCING ACTIVITIES		
Capital Contribution from Parent	120,000	-
Issuance of Long-term Debt – Nonaffiliated	567,797	115,553
Issuance of Long-term Debt – Affiliated	25,000	-
Change in Advances from Affiliates, Net	(473,686)	227,643
Retirement of Long-term Debt – Nonaffiliated	-	(262,000)
Retirement of Cumulative Preferred Stock	(2)	-
Principal Payments for Capital Lease Obligations	(16,235)	(18,935)
Dividends Paid on Common Stock	(49,000)	(37,500)
Dividends Paid on Cumulative Preferred Stock	(170)	(170)
Other Financing Activities	189	-
Net Cash Flows from Financing Activities	173,893	24,591
Net Increase (Decrease) in Cash and Cash Equivalents	84	(157)
Cash and Cash Equivalents at Beginning of Period	728	1,139
Cash and Cash Equivalents at End of Period	$ 812	$ 982
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 51,199	$ 38,706
Net Cash Paid (Received) for Income Taxes	(23)	13,827
Noncash Acquisitions Under Capital Leases	1,380	2,911
Construction Expenditures Included in Accounts Payable at June 30,	26,763	20,650
Acquisition of Nuclear Fuel Included in Accounts Payable at June 30,	9	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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. The footnotes begin on page H-1.

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Net Income
(in millions)

Second Quarter of 2008		$	53
Changes in Gross Margin:			
Retail Margins	81		
Off-system Sales	(32)		
Other	(3)		
Total Change in Gross Margin			46
Total Expenses and Other:			
Other Operation and Maintenance	(3)		
Depreciation and Amortization	(18)		
Carrying Costs Income	(2)		
Other Income	(2)		
Interest Expense	6		
Total Expenses and Other			(19)
Income Tax Expense			(16)
Second Quarter of 2009		$	64

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 $81 million primarily due to the following:
  - A $45 million increase related to the implementation of higher rates set by the Ohio ESP.
  - A $29 million increase related to a coal contract amendment in the second quarter of 2008.
  - A $24 million increase in fuel margins due to the deferral of fuel costs in 2009. The PUCO's March 2009 approval of OPCo's ESP allows for the recovery of fuel and related costs beginning January 1, 2009. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $13 million increase in capacity settlements under the Interconnection Agreement.

  These increases were partially offset by:
  - A $21 million decrease in industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in OPCo's service territory.
- Margins from Off-system Sales decreased $32 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.
- Other revenues decreased $3 million primarily due to decreased gains on sales of emission allowances. Due to the implementation of OPCo's ESP as discussed above, emission gains and losses incurred after January 1, 2009 will be included in OPCo's fuel adjustment clause.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $3 million primarily due to:
  - A $6 million increase in maintenance of overhead lines primarily due to increased vegetation management activities.
  - A $5 million increase in removal costs at the Gavin and Mitchell Plants.

  These increases were partially offset by:
  - A $5 million decrease in maintenance expenses from planned and forced outages at various plants.
  - A $4 million decrease in recoverable PJM expenses.

- Depreciation and Amortization increased $18 million primarily due to:
  - A $21 million increase from higher depreciable property balances as a result of environmental improvements placed in service and various other property additions and higher depreciation rates related to shortened depreciable lives for certain generating facilities.

  The increase was partially offset by:
  - A $7 million decrease due to the completion of the amortization of regulatory assets in December 2008.
- Interest Expense decreased $6 million primarily due to an unrealized gain on an interest rate hedge of a forecasted debt issuance.
- Income Tax Expense increased $16 million primarily due to an increase in pretax book income and state income taxes.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Net Income
(in millions)

Six Months Ended June 30, 2008		$	192
Changes in Gross Margin:			
Retail Margins	44		
Off-system Sales	(61)		
Other	7		
Total Change in Gross Margin			(10)
Total Expenses and Other:			
Other Operation and Maintenance	(24)		
Depreciation and Amortization	(34)		
Carrying Costs Income	(4)		
Other Income	(4)		
Interest Expense	1		
Total Expenses and Other			(65)
Income Tax Expense			20
Six Months Ended June 30, 2009		$	137

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 increased $44 million primarily due to the following:
  - A $53 million increase related to the implementation of higher rates set by the Ohio ESP.
  - A $25 million increase in fuel margins due to the deferral of fuel costs in 2009. The PUCO's March 2009 approval of OPCo's ESP allows for the recovery of fuel and related costs beginning January 1, 2009. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $22 million increase in capacity settlements under the Interconnection Agreement.

  These increases were partially offset by:
  - A $30 million decrease in industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in OPCo's service territory.
  - A $29 million decrease related to coal contract amendments recorded in 2008.
- Margins from Off-system Sales decreased $61 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading margins.
- Other revenues increased $7 million primarily due to increased gains on sales of emission allowances. Due to the implementation of OPCo's ESP as discussed above, emission gains and losses incurred after January 1, 2009 will be included in OPCo's fuel adjustment clause.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $24 million primarily due to:
  - A $7 million increase in maintenance of overhead lines due to ice and wind storm costs incurred in January and February 2009 and a $7 million increase in vegetation management activities.
  - A $6 million increase related to an obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of OPCo's ESP. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $5 million increase in removal costs at Gavin and Mitchell Plants.
- Depreciation and Amortization increased $34 million primarily due to:
  - A $39 million increase from higher depreciable property balances as a result of environmental improvements placed in service and various other property additions and higher depreciation rates related to shortened depreciable lives for certain generating facilities.
  - A $5 million increase as a result of the completion of the amortization of a regulated liability in December 2008 related to energy sales to Ormet at below market rates. See "Ormet" section of Note 3.

  These increases were partially offset by:
  - A $14 million decrease due to the completion of the amortization of regulatory assets in December 2008.
- Income Tax Expense decreased $20 million primarily due to a decrease in pretax book income partially offset by an increase in state income taxes.

Financial Condition

Credit Ratings

OPCo's credit ratings as of June 30, 2009 were as follows:

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

S&P and Fitch have OPCo on stable outlook while Moody's has OPCo on negative outlook. In January 2009, Moody's placed OPCo on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries. If OPCo receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the six months ended June 30, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 12,679	$ 6,666
Cash Flows from (Used for):		
Operating Activities	(19,453)	290,822
Investing Activities	(296,508)	(271,527)
Financing Activities	320,054	(15,863)
Net Increase in Cash and Cash Equivalents	4,093	3,432
Cash and Cash Equivalents at End of Period	$ 16,772	$ 10,098

Operating Activities

Net Cash Flows Used for Operating Activities were $19 million in 2009. OPCo produced income of $137 million during the period and had noncash expense items of $173 million for Depreciation and Amortization, $117 million for Deferred Income Taxes and $44 million for Deferred Property Taxes offset by a $142 million increase in Fuel Over/Under-Recovery due to an under-recovery of fuel costs in Ohio. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital primarily relates to a number of items. Fuel, Materials and Supplies had a $166 million outflow primarily due to an increase in coal inventory. Accounts Payable had a $101 million outflow primarily due to OPCo's provision for revenue refund of $62 million which was paid in the first quarter 2009 to the AEP West companies as part of the FERC's recent order on the SIA. Accrued Taxes, Net had a $93 million outflow due to a decrease of federal income tax related accruals and temporary timing differences of payments for property taxes.

Net Cash Flows from Operating Activities were $291 million in 2008. OPCo produced Net Income of $192 million during the period and a noncash expense item of $140 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. Accounts Payable had a $47 million inflow primarily due to increases in tonnage and prices per ton related to fuel and consumable purchases. Fuel, Materials and Supplies had a $41 million outflow due to price increases. Accounts Receivable, Net had a $38 million outflow primarily due to a coal contract amendment which reduced future deliveries in exchange for consideration received.

Investing Activities

Net Cash Used for Investing Activities were $297 million and $272 million in 2009 and 2008, respectively. Construction Expenditures were $276 million and $277 million in 2009 and 2008, 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. OPCo forecasts approximately $439 million of construction expenditures for all of 2009, excluding AFUDC. OPCo had a net increase of $40 million in investments in the Utility Money Pool in 2009.

Financing Activities

Net Cash Flows from Financing Activities were $320 million in 2009 primarily due to a $550 million Capital Contribution from Parent partially offset by a net decrease of $134 million in borrowings from the Utility Money Pool and a $78 million retirement of Notes Payable.

Net Cash Flows Used for Financing Activities were $16 million in 2008. OPCo issued $165 million of Pollution Control Bonds and retired $250 million of Pollution Control Bonds. OPCo had a net increase in borrowings of $72 million from the Utility Money Pool.

Financing Activity

Long-term debt issuances, retirements and principal payments made during the first six months of 2009 were:

Issuances

None

Retirements and Principal Payments

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable – Nonaffiliated	$ 6,500	7.21	2009
Notes Payable – Nonaffiliated	1,000	6.27	2009
Notes Payable – Nonaffiliated	70,000	7.49	2009

Liquidity

The financial markets remain volatile at both a global and domestic level. The uncertainties in the capital markets could have significant implications on OPCo since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on OPCo's operations and ability to issue debt at reasonable interest rates.

OPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. OPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2008 Annual Report and has not changed significantly from year-end other than the debt retirements discussed in "Cash Flow" and "Financing Activity" above.

Purchase of JMG Funding Equity

OPCo has a lease agreement with JMG to finance OPCo's Flue Gas Desulfurization (FGD) system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. As of June 30, 2009, $218 million of outstanding auction-rate debt related to JMG. Interest rates on this debt are at the contractual maximum rate of 13%. OPCo was unable to refinance this debt without JMG's consent. OPCo sought approval from the PUCO to terminate the JMG relationship and received the approval in June 2009. In July 2009, they purchased the outstanding equity ownership of JMG for $28 million. OPCo plans to refinance the related outstanding debt as market conditions permit. Management's intent is to dissolve JMG. The assets and liabilities of JMG will remain incorporated with OPCo's business.

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 regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2008 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 beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 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 2008 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 beginning on page I-1 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 OPCo's Condensed Consolidated Balance Sheet as of June 30, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to Condensed Consolidated Balance Sheet June 30, 2009 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 66,735	$ 32,840	$ -	$ (3,671)	$ 95,904
Noncurrent Assets	43,026	735	-	(3,592)	40,169
Total MTM Derivative Contract Assets	109,761	33,575	-	(7,263)	136,073
Current Liabilities	42,441	871	1,773	(12,201)	32,884
Noncurrent Liabilities	26,616	671	834	(9,599)	18,522
Total MTM Derivative Contract Liabilities	69,057	1,542	2,607	(21,800)	51,406
Total MTM Derivative Contract Net Assets (Liabilities)	$ 40,704	$ 32,033	$ (2,607)	$ 14,537	$ 84,667

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	37,761
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(13,137)
Fair Value of New Contracts at Inception When Entered During the Period (a)		7,469
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		(135)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		7,511
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		1,235
Total MTM Risk Management Contract Net Assets		40,704
Cash Flow Hedge Contracts		32,033
DETM Assignment (d)		(2,607)
Collateral Deposits		14,537
Ending Net Risk Management Assets at June 30, 2009	$	84,667

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(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.
(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

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

The following table presents 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 (Liabilities)
June 30, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (692)	$ (19)	$ 1	$ -	$ -	$ -	$ (710)
Level 2 (b)	11,069	9,369	3,263	112	743	266	24,822
Level 3 (c)	3,201	4,199	1,406	618	(14)	-	9,410
Total	13,578	13,549	4,670	730	729	266	33,522
Dedesignated Risk Management Contracts (d)	1,630	3,195	1,244	1,113	-	-	7,182
Total MTM Risk Management Contract Net Assets	$ 15,208	$ 16,744	$ 5,914	$ 1,843	$ 729	$ 266	$ 40,704

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1 and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.
(d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contracts.

Credit Risk

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

See Note 8 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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, 2009, a near term typical change in commodity prices is not expected to have a material effect on net income, 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, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$277	$530	$271	$113	$140	$1,284	$411	$131

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management's back-testing results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes OPCo's VaR calculation is conservative.

As OPCo's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand OPCo's exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which OPCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on OPCo's debt outstanding as of June 30, 2009, the estimated EaR on OPCo's debt portfolio for the following twelve months was $9.1 million.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2009	**2008**	**2009**	**2008**
REVENUES				
Electric Generation, Transmission and Distribution	$ 457,465	$ 515,884	$ 982,151	$ 1,071,362
Sales to AEP Affiliates	210,998	256,399	437,692	493,247
Other Revenues – Affiliated	6,281	6,487	13,769	11,786
Other Revenues – Nonaffiliated	3,269	3,591	7,116	8,154
TOTAL REVENUES	678,013	782,361	1,440,728	1,584,549
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	189,475	330,190	442,949	569,124
Purchased Electricity for Resale	43,969	39,155	96,238	73,732
Purchased Electricity from AEP Affiliates	20,465	35,157	37,207	67,673
Other Operation	96,249	91,959	195,847	181,841
Maintenance	58,150	59,218	118,190	107,915
Depreciation and Amortization	89,384	71,173	173,407	139,739
Taxes Other Than Income Taxes	46,482	45,937	97,974	97,515
TOTAL EXPENSES	544,174	672,789	1,161,812	1,237,539
OPERATING INCOME	133,839	109,572	278,916	347,010
Other Income (Expense):				
Other Income	417	2,452	1,528	5,904
Carrying Costs Income	2,425	3,994	4,009	8,223
Interest Expense	(35,241)	(41,438)	(73,922)	(75,357)
INCOME BEFORE INCOME TAX EXPENSE	101,440	74,580	210,531	285,780
Income Tax Expense	37,528	21,271	74,010	94,181
NET INCOME	63,912	53,309	136,521	191,599
Less: Net Income Attributable to Noncontrolling Interest	553	415	1,016	878
NET INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	63,359	52,894	135,505	190,721
Less: Preferred Stock Dividend Requirements	183	183	366	366
EARNINGS ATTRIBUTABLE TO OPCo COMMON SHAREHOLDER	$ 63,176	$ 52,711	$ 135,139	$ 190,355

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	OPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2007	$ 321,201	$ 536,640	$ 1,469,717	$ (36,541)	$ 15,923	$ 2,306,940
EITF 06-10 Adoption, Net of Tax of $1,004			(1,864)			(1,864)
SFAS 157 Adoption, Net of Tax of $152			(282)			(282)
Common Stock Dividends – Nonaffiliated					(878)	(878)
Preferred Stock Dividends			(366)			(366)
Other Changes in Equity					1,524	1,524
SUBTOTAL – EQUITY						2,305,074
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of $6,732				(12,502)		(12,502)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $758				1,406		1,406
NET INCOME			190,721		878	191,599
TOTAL COMPREHENSIVE INCOME						180,503
TOTAL EQUITY – JUNE 30, 2008	$ 321,201	$ 536,640	$ 1,657,926	$ (47,637)	$ 17,447	$ 2,485,577
TOTAL EQUITY – DECEMBER 31, 2008	$ 321,201	$ 536,640	$ 1,697,962	$ (133,858)	$ 16,799	$ 2,438,744
Capital Contribution from Parent		550,000				550,000
Common Stock Dividends – Affiliated			(25,000)			(25,000)
Common Stock Dividends – Nonaffiliated					(1,016)	(1,016)
Preferred Stock Dividends			(366)			(366)
Other Changes in Equity					1,111	1,111
SUBTOTAL – EQUITY						2,963,473
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $7,828				14,538		14,538
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,459				2,709		2,709
NET INCOME			135,505		1,016	136,521
TOTAL COMPREHENSIVE INCOME						153,768
TOTAL EQUITY – JUNE 30, 2009	$ 321,201	$ 1,086,640	$ 1,808,101	$ (116,611)	$ 17,910	$ 3,117,241

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 16,772	$ 12,679
Advances to Affiliates	40,319	-
Accounts Receivable:		
Customers	71,877	91,235
Affiliated Companies	135,260	118,721
Accrued Unbilled Revenues	15,233	18,239
Miscellaneous	6,726	23,393
Allowance for Uncollectible Accounts	(3,996)	(3,586)
Total Accounts Receivable	225,100	248,002
Fuel	347,050	186,904
Materials and Supplies	112,921	107,419
Risk Management Assets	95,904	53,292
Accrued Tax Benefits	53,941	13,568
Prepayments and Other Current Assets	46,105	42,999
TOTAL CURRENT ASSETS	938,112	664,863
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	6,656,180	6,025,277
Transmission	1,149,422	1,111,637
Distribution	1,515,437	1,472,906
Other Property, Plant and Equipment	372,229	391,862
Construction Work in Progress	247,703	787,180
Total Property, Plant and Equipment	9,940,971	9,788,862
Accumulated Depreciation and Amortization	3,208,227	3,122,989
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,732,744	6,665,873
OTHER NONCURRENT ASSETS		
Regulatory Assets	585,234	449,216
Long-term Risk Management Assets	40,169	39,097
Deferred Charges and Other Noncurrent Assets	137,138	184,777
TOTAL OTHER NONCURRENT ASSETS	762,541	673,090
TOTAL ASSETS	$ 8,433,397	$ 8,003,826

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 133,887
Accounts Payable:		
General	173,266	193,675
Affiliated Companies	109,313	206,984
Short-term Debt – Nonaffiliated	11,500	-
Long-term Debt Due Within One Year – Nonaffiliated	479,450	77,500
Risk Management Liabilities	32,884	29,218
Customer Deposits	26,102	24,333
Accrued Taxes	134,477	187,256
Accrued Interest	40,677	44,245
Other Current Liabilities	190,281	163,702
TOTAL CURRENT LIABILITIES	1,197,950	1,060,800
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,282,752	2,761,876
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	18,522	23,817
Deferred Income Taxes	1,022,642	927,072
Regulatory Liabilities and Deferred Investment Tax Credits	128,985	127,788
Employee Benefits and Pension Obligations	283,345	288,106
Deferred Credits and Other Noncurrent Liabilities	165,334	158,996
TOTAL NONCURRENT LIABILITIES	4,101,580	4,487,655
TOTAL LIABILITIES	5,299,530	5,548,455
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,626	16,627
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,086,640	536,640
Retained Earnings	1,808,101	1,697,962
Accumulated Other Comprehensive Income (Loss)	(116,611)	(133,858)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,099,331	2,421,945
Noncontrolling Interest	17,910	16,799
TOTAL EQUITY	3,117,241	2,438,744
TOTAL LIABILITIES AND EQUITY	$ 8,433,397	$ 8,003,826

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 136,521	$ 191,599
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	173,407	139,739
Deferred Income Taxes	117,372	27,984
Carrying Costs Income	(4,009)	(8,223)
Allowance for Equity Funds Used During Construction	(768)	(1,246)
Mark-to-Market of Risk Management Contracts	(16,123)	2,018
Deferred Property Taxes	44,125	42,089
Fuel Over/Under-Recovery, Net	(141,874)	-
Change in Other Noncurrent Assets	6,483	(59,294)
Change in Other Noncurrent Liabilities	15,173	13,265
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	20,986	(38,279)
Fuel, Materials and Supplies	(165,648)	(40,620)
Accounts Payable	(100,613)	47,035
Accrued Taxes, Net	(93,152)	(5,865)
Other Current Assets	(14,965)	(9,620)
Other Current Liabilities	3,632	(9,760)
Net Cash Flows from (Used for) Operating Activities	(19,453)	290,822
INVESTING ACTIVITIES		
Construction Expenditures	(276,255)	(276,911)
Change in Advances to Affiliates, Net	(40,319)	-
Proceeds from Sales of Assets	17,261	5,889
Other Investing Activities	2,805	(505)
Net Cash Flows Used for Investing Activities	(296,508)	(271,527)
FINANCING ACTIVITIES		
Capital Contribution from Parent	550,000	-
Issuance of Long-term Debt – Nonaffiliated	(445)	164,474
Change in Short-term Debt, Net – Nonaffiliated	11,500	(701)
Change in Advances from Affiliates, Net	(133,887)	72,285
Retirement of Long-term Debt – Nonaffiliated	(77,500)	(257,463)
Retirement of Cumulative Preferred Stock	(1)	-
Principal Payments for Capital Lease Obligations	(2,224)	(3,214)
Funds from Amended Coal Contact	-	10,000
Dividends Paid on Common Stock – Nonaffiliated	(463)	(878)
Dividends Paid on Common Stock – Affiliated	(25,000)	-
Dividends Paid on Cumulative Preferred Stock	(366)	(366)
Other Financing Activities	(1,560)	-
Net Cash Flows from (Used for) Financing Activities	320,054	(15,863)
Net Increase in Cash and Cash Equivalents	4,093	3,432
Cash and Cash Equivalents at Beginning of Period	12,679	6,666
Cash and Cash Equivalents at End of Period	$ 16,772	$ 10,098
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 100,522	$ 72,685
Net Cash Paid for Income Taxes	2,566	32,569
Noncash Acquisitions Under Capital Leases	468	1,673
Noncash Acquisition of Coal Land Rights	-	41,600
Construction Expenditures Included in Accounts Payable at June 30,	16,391	27,610

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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. The footnotes begin on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA

Results of Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Net Income
(in millions)

Second Quarter of 2008		$ 4
Changes in Gross Margin:		
Retail and Off-system Sales Margins	32	
Other	2	
Total Change in Gross Margin		34
Total Expenses and Other:		
Other Operation and Maintenance	(4)	
Deferral of Ice Storm Costs	8	
Depreciation and Amortization	(4)	
Other Income	(1)	
Interest Expense	(1)	
Total Expenses and Other		(2)
Income Tax Expense		(12)
Second Quarter of 2009		$ 24

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 and Off-system Sales Margins increased $32 million primarily due to an increase in retail sales margins resulting from base rate adjustments.
- Other revenues increased $2 million primarily due to higher third party nonutility construction projects and nonaffiliated rent revenue.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million primarily due to:
  - A $7 million increase due to a prior year credit adjustment related to the December 2007 ice storm.
  - A $2 million increase in employee-related expenses.
  - A $1 million increase in transmission operating expense primarily due to higher SPP costs.

  These increases were partially offset by:
  - A $6 million decrease in generation plant maintenance expense primarily due to higher planned maintenance in 2008.
- Deferral of Ice Storm Costs decreased $8 million due to 2008 costs and true-up entries to adjust actual December 2007 ice storm costs to the 2007 estimated accrual.
- Depreciation and Amortization expenses increased $4 million primarily due to the amortization of regulatory assets, largest of which was related to the Generation Cost Recovery regulatory asset.
- Income Tax Expense increased $12 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Net Income
(in millions)

Six Months Ended June 30, 2008		$	42
Changes in Gross Margin:			
Retail and Off-system Sales Margins	49		
Transmission Revenues	1		
Other	(8)		
Total Change in Gross Margin			42
Total Expenses and Other:			
Other Operation and Maintenance	22		
Deferral of Ice Storm Costs	(72)		
Depreciation and Amortization	(6)		
Other Income	(3)		
Interest Expense	(1)		
Total Expenses and Other			(60)
Income Tax Expense			6
Six Months Ended June 30, 2009		$	30

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 and Off-system Sales Margins increased $49 million primarily due to an increase in retail sales margins resulting from base rate adjustments.
- Other revenues decreased $8 million related to the sale of SO_2 allowances.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $22 million primarily due to:
  - The write-off in the first quarter of 2008 of $10 million of unrecoverable pre-construction costs related to the cancelled Red Rock Generating Facility.
  - An $8 million decrease due to lower plant maintenance expense primarily due to the deferral of generation maintenance expenses as a result of PSO's base rate filing. See "2008 Oklahoma Base Rate Filing" section of Note 3.
  - A $2 million decrease in employee-related expenses.
- Deferral of Ice Storm Costs in 2008 of $72 million results from an OCC order approving recovery of ice storm costs related to ice storms in January and December 2007.
- Depreciation and Amortization expenses increased $6 million primarily due to the amortization of regulatory assets, largest of which was related to the Generation Cost Recovery regulatory asset.
- Other Income decreased $3 million primarily due to carrying charges related to the Generation Cost Recovery regulatory assets and a decrease in the equity component of AFUDC.
- Income Tax Expense decreased $6 million primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

PSO's credit ratings as of June 30, 2009 were as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa1	BBB	BBB+

S&P, Moody's and Fitch have PSO on stable outlook. If PSO receives a downgrade from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the six months ended June 30, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,345	$ 1,370
Cash Flows from (Used for):		
Operating Activities	199,675	(6,309)
Investing Activities	(118,301)	(99,942)
Financing Activities	(81,659)	106,405
Net Increase (Decrease) in Cash and Cash Equivalents	(285)	154
Cash and Cash Equivalents at End of Period	$ 1,060	$ 1,524

Operating Activities

Net Cash Flows from Operating Activities were $200 million in 2009. PSO produced Net Income of $30 million during the period and had a noncash expense item of $56 million for Depreciation and Amortization, partially offset by a $19 million increase in Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $88 million inflow from Accounts Receivable, Net was primarily due to receiving the SIA refund from the AEP East companies and lower customer receivables. The $40 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The $15 million inflow from Fuel Over/Under-Recovery, Net was primarily due to lower fuel costs, partially offset by SIA refunds to customers.

Net Cash Flows Used for Operating Activities were $6 million in 2008. PSO produced Net Income of $42 million during the period and had noncash expense items of $71 million for Deferred Income Taxes and $51 million for Depreciation and Amortization. PSO established a $72 million regulatory asset for an OCC order approving recovery of ice storm costs related to storms in January and December 2007. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital primarily relates to Fuel Over/Under-Recovery, Net which had a $74 million outflow as a result of rapidly increasing cost of natural gas which fuels the majority of PSO's generators.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $118 million and $100 million, respectively. Construction Expenditures of $99 million and $152 million in 2009 and 2008, respectively, were primarily related to projects for improved generation, transmission and distribution service reliability. During 2009, PSO had a net increase of $19 million in loans to the Utility Money Pool. During 2008, PSO had a net decrease of $51 million in loans to the Utility Money Pool. PSO forecasts approximately $188 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows Used for Financing Activities were $82 million during 2009. PSO had a net decrease of $70 million in borrowings from the Utility Money Pool. PSO retired $50 million of Senior Unsecured Notes in June 2009 and issued $34 million of Pollution Control Bonds in February 2009. PSO received capital contributions from the Parent of $20 million. In addition, PSO paid $15 million in dividends on common stock.

Net Cash Flows from Financing Activities were $106 million during 2008. PSO had a net increase of $111 million in borrowings from the Utility Money Pool. PSO repurchased $34 million in Pollution Control bonds in May 2008. PSO received capital contributions from the Parent of $30 million.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2009 were:

<u>Issuances</u>

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Pollution Control Bonds	$ 33,700	5.25	2014

<u>Retirements</u>

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 50,000	4.70	2009

Liquidity

Although the financial markets remain volatile at both a global and domestic level, PSO issued $34 million of Pollution Control Bonds during the first six months of 2009. The uncertainties in the capital markets could have significant implications on PSO since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on PSO's operations and ability to issue debt at reasonable interest rates.

PSO participates in the Utility Money Pool, which provides access to AEP's liquidity. PSO will rely upon cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of liquidity.

<u>Summary Obligation Information</u>

A summary of contractual obligations is included in the 2008 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.

<u>Significant Factors</u>

New Generation/Purchased Power Agreement

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 additional discussion of relevant factors.

Litigation and Regulatory Activity

In the ordinary course of business, PSO 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 regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2008 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 beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 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 2008 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 beginning on page I-1 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 PSO.

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in PSO's Condensed Balance Sheet as of June 30, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to Condensed Balance Sheet June 30, 2009 (in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 5,144	$ 164	$ -	$ -	$ 5,308
Noncurrent Assets	400	71	-	-	471
Total MTM Derivative Contract Assets	5,544	235	-	-	5,779
Current Liabilities	4,684	54	65	(123)	4,680
Noncurrent Liabilities	337	-	30	(13)	354
Total MTM Derivative Contract Liabilities	5,021	54	95	(136)	5,034
Total MTM Derivative Contract Net Assets (Liabilities)	$ 523	$ 181	$ (95)	$ 136	$ 745

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	1,660
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(437)
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		(17)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(19)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(664)
Total MTM Risk Management Contract Net Assets		523
Cash Flow Hedge Contracts		181
DETM Assignment (d)		(95)
Collateral Deposits		136
Ending Net Risk Management Assets at June 30, 2009	$	745

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

(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 Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

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

The following table presents 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 (Liabilities)
June 30, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (140)	$ -	$ -	$ -	$ -	$ -	$ (140)
Level 2 (b)	609	236	(186)	(8)	-	-	651
Level 3 (c)	11	1	-	-	-	-	12
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 480	$ 237	$ (186)	$ (8)	$ -	$ -	$ 523

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1 and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Credit Risk

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

See Note 8 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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, 2009, a near term typical change in commodity prices is not expected to have a material effect on PSO's net income, 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, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$15	$34	$12	$4	$4	$164	$44	$6

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management's back-testing results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes PSO's VaR calculation is conservative.

As PSO's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand PSO's exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which PSO's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on PSO's debt outstanding as of June 30, 2009, the estimated EaR on PSO's debt portfolio for the following twelve months was $3.4 million.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended 2009	Three Months Ended 2008	Six Months Ended 2009	Six Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 263,763	$ 357,675	$ 542,534	$ 676,555
Sales to AEP Affiliates	11,690	41,767	27,513	57,702
Other Revenues	1,688	892	2,381	2,077
TOTAL REVENUES	277,141	400,334	572,428	736,334
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	62,753	143,537	182,152	296,742
Purchased Electricity for Resale	46,108	104,016	90,533	152,598
Purchased Electricity from AEP Affiliates	3,416	21,506	9,331	38,775
Other Operation	46,521	45,186	86,066	101,185
Maintenance	27,965	25,655	53,395	60,242
Deferral of Ice Storm Costs	-	8,223	-	(71,679)
Depreciation and Amortization	28,529	24,720	56,479	50,887
Taxes Other Than Income Taxes	10,958	10,474	21,709	21,426
TOTAL EXPENSES	226,250	383,317	499,665	650,176
OPERATING INCOME	50,891	17,017	72,763	86,158
Other Income (Expense):				
Interest Income	580	967	1,228	2,095
Carrying Costs Income	1,019	2,128	2,730	3,762
Allowance for Equity Funds Used During Construction	571	516	741	1,875
Interest Expense	(15,163)	(14,525)	(29,968)	(29,466)
INCOME BEFORE INCOME TAX EXPENSE	37,898	6,103	47,494	64,424
Income Tax Expense	13,776	1,976	17,334	22,898
NET INCOME	24,122	4,127	30,160	41,526
Preferred Stock Dividend Requirements	53	53	106	106
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 24,069	$ 4,074	$ 30,054	$ 41,420

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	$ 157,230	$ 310,016	$ 174,539	$ (887)	$ 640,898
EITF 06-10 Adoption, Net of Tax of $596			(1,107)		(1,107)
Capital Contribution from Parent		30,000			30,000
Preferred Stock Dividends			(106)		(106)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					669,685
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $49				91	91
NET INCOME			41,526		41,526
TOTAL COMPREHENSIVE INCOME					41,617
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2008	$ 157,230	$ 340,016	$ 214,852	$ (796)	$ 711,302
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 157,230	$ 340,016	$ 251,704	$ (704)	$ 748,246
Capital Contribution from Parent		20,000			20,000
Common Stock Dividends			(14,500)		(14,500)
Preferred Stock Dividends			(106)		(106)
Gain on Reacquired Preferred Stock		1			1
Other Changes in Common Shareholder's Equity		4,214	(4,214)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					753,641
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $117				218	218
NET INCOME			30,160		30,160
TOTAL COMPREHENSIVE INCOME					30,378
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009	$ 157,230	$ 364,231	$ 263,044	$ (486)	$ 784,019

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,060	$ 1,345
Advances to Affiliates	19,438	-
Accounts Receivable:		
Customers	28,425	39,823
Affiliated Companies	60,841	138,665
Miscellaneous	6,841	8,441
Allowance for Uncollectible Accounts	(33)	(20)
Total Accounts Receivable	96,074	186,909
Fuel	22,055	27,060
Materials and Supplies	44,730	44,047
Risk Management Assets	5,308	5,830
Deferred Tax Benefits	33,922	9,123
Accrued Tax Benefits	1,759	3,876
Prepayments and Other Current Assets	3,010	3,371
TOTAL CURRENT ASSETS	227,356	281,561
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,289,840	1,266,716
Transmission	636,041	622,665
Distribution	1,524,892	1,468,481
Other Property, Plant and Equipment	248,602	248,897
Construction Work in Progress	59,702	85,252
Total Property, Plant and Equipment	3,759,077	3,692,011
Accumulated Depreciation and Amortization	1,215,036	1,192,130
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,544,041	2,499,881
OTHER NONCURRENT ASSETS		
Regulatory Assets	289,511	304,737
Long-term Risk Management Assets	471	917
Deferred Charges and Other Noncurrent Assets	32,558	13,702
TOTAL OTHER NONCURRENT ASSETS	322,540	319,356
TOTAL ASSETS	$ 3,093,937	$ 3,100,798

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 70,308
Accounts Payable:		
General	66,804	84,121
Affiliated Companies	99,632	86,407
Long-term Debt Due Within One Year – Nonaffiliated	-	50,000
Risk Management Liabilities	4,680	4,753
Customer Deposits	42,375	40,528
Accrued Taxes	56,683	19,000
Regulatory Liability for Over-Recovered Fuel Costs	125,817	58,395
Provision for Revenue Refund	-	52,100
Other Current Liabilities	45,005	61,194
TOTAL CURRENT LIABILITIES	440,996	526,806
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	868,679	834,859
Long-term Risk Management Liabilities	354	378
Deferred Income Taxes	532,873	514,720
Regulatory Liabilities and Deferred Investment Tax Credits	323,441	323,750
Deferred Credits and Other Noncurrent Liabilities	138,317	146,777
TOTAL NONCURRENT LIABILITIES	1,863,664	1,820,484
TOTAL LIABILITIES	2,304,660	2,347,290
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,258	5,262
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	364,231	340,016
Retained Earnings	263,044	251,704
Accumulated Other Comprehensive Income (Loss)	(486)	(704)
TOTAL COMMON SHAREHOLDER'S EQUITY	784,019	748,246
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,093,937	$ 3,100,798

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 30,160	$ 41,526
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	56,479	50,887
Deferred Income Taxes	(6,130)	70,618
Deferral of Ice Storm Costs	-	(71,679)
Allowance for Equity Funds Used During Construction	(741)	(1,875)
Mark-to-Market of Risk Management Contracts	1,053	2,216
Deferred Property Taxes	(18,700)	(17,796)
Change in Other Noncurrent Assets	(845)	25,981
Change in Other Noncurrent Liabilities	(3,290)	(33,384)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	87,923	1,270
Fuel, Materials and Supplies	4,322	(7,964)
Margin Deposits	286	7,988
Accounts Payable	7,980	18,238
Accrued Taxes, Net	39,800	(2,317)
Fuel Over/Under-Recovery, Net	15,268	(73,573)
Other Current Assets	(171)	820
Other Current Liabilities	(13,719)	(17,265)
Net Cash Flows from (Used for) Operating Activities	199,675	(6,309)
INVESTING ACTIVITIES		
Construction Expenditures	(98,559)	(151,711)
Change in Advances to Affiliates, Net	(19,438)	51,202
Other Investing Activities	(304)	567
Net Cash Flows Used for Investing Activities	(118,301)	(99,942)
FINANCING ACTIVITIES		
Capital Contribution from Parent	20,000	30,000
Issuance of Long-term Debt – Nonaffiliated	33,283	-
Change in Advances from Affiliates, Net	(70,308)	110,981
Retirement of Long-term Debt – Nonaffiliated	(50,000)	(33,700)
Retirement of Cumulative Preferred Stock	(2)	-
Principal Payments for Capital Lease Obligations	(772)	(770)
Dividends Paid on Common Stock	(14,500)	-
Dividends Paid on Cumulative Preferred Stock	(106)	(106)
Other Financing Activities	746	-
Net Cash Flows from (Used for) Financing Activities	(81,659)	106,405
Net Increase (Decrease) in Cash and Cash Equivalents	(285)	154
Cash and Cash Equivalents at Beginning of Period	1,345	1,370
Cash and Cash Equivalents at End of Period	$ 1,060	$ 1,524
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 44,038	$ 27,774
Net Cash Paid (Received) for Income Taxes	3,584	(19,529)
Noncash Acquisitions Under Capital Leases	522	253
Construction Expenditures Included in Accounts Payable at June 30,	5,932	11,731

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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. The footnotes begin on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

Results of Operations

Second Quarter of 2009 Compared to Second Quarter of 2008

**Reconciliation of Second Quarter of 2008 to Second Quarter of 2009
Income Before Extraordinary Loss
(in millions)**

Second Quarter of 2008		$	15
Changes in Gross Margin:			
Retail and Off-system Sales Margins (a)	10		
Transmission Revenues	3		
Total Change in Gross Margin			13
Total Expenses and Other:			
Other Operation and Maintenance	4		
Depreciation and Amortization	1		
Other Income	8		
Interest Expense	(2)		
Total Expenses and Other			11
Income Tax Expense			(3)
Second Quarter of 2009		$	36

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

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 and Off-system Sales Margins increased $10 million primarily due to:
  - A $9 million increase in fuel recovery primarily due to a higher FERC fuel recovery level in 2009 for formula rate customers.
  - A $4 million increase in rate relief related to the Louisiana Formula Rate Plan. See "Louisiana Rate Matters – Formula Rate Filing" section of Note 3.

  These increases are partially offset by:
  - A $4 million decrease in industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in SWEPCo's service territory.
- Transmission Revenues increased $3 million primarily due to higher rates in the SPP region.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $4 million primarily due to a decrease in distribution expense resulting from the capitalization of a portion of the January 2009 Northern Arkansas ice storm costs for new assets installed.
- Other Income increased $8 million primarily due to an increase in the equity component of AFUDC as a result of construction at the Turk Plant and Stall Unit and the reapplication of SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009. See "Texas Rate Matters – Texas Restructuring – SPP" section of Note 3.
- Interest Expense increased $2 million primarily due to higher interest expense on debt to fund new generation capital expenditures partially offset by higher AFUDC debt.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income and state income taxes, partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Reconciliation of Six Months Ended June 30, 2008 to Six Months Ended June 30, 2009
Income Before Extraordinary Loss
(in millions)

Six Months Ended June 30, 2008		$ 21
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	6	
Transmission Revenues	5	
Other	(2)	
Total Change in Gross Margin		9
Total Expenses and Other:		
Other Operation and Maintenance	14	
Taxes Other Than Income Taxes	2	
Other Income	11	
Interest Expense	(1)	
Total Expenses and Other		26
Income Tax Expense		(9)
Six Months Ended June 30, 2009		$ 47

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

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 and Off-system Sales Margins increased $6 million primarily due to:
  - A $7 million increase in rate relief related to the Louisiana Formula Rate Plan. See “Louisiana Rate Matters – Formula Rate Filing” section of Note 3.
  - A $6 million increase in wholesale and municipal revenue due to the annual true-up for formula rate customers in 2009 and to higher prices.
  - A $5 million increase in fuel recovery due to a higher FERC fuel recovery level in 2009 for formula rate customers.

  These increases are partially offset by:
  - A $12 million decrease in retail sales margins primarily related to reduced customer usage. A $7 million decrease was experienced in the industrial sector due to reduced operating levels and suspended operations by certain large industrial customers in SWEPCo’s service territory.
- Transmission Revenues increased $5 million primarily due to higher rates in the SPP region.
- Other revenues decreased $2 million primarily due to a decrease in revenues from coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC to Cleco Corporation, a nonaffiliated entity. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $14 million primarily due to:
  - A $5 million decrease in steam plant maintenance expense primarily due to a reduction in planned and unplanned outages.
  - A $3 million decrease in expenses for coal deliveries from SWEPCo’s mining subsidiary, Dolet Hills Lignite Company, LLC. The decreased expenses for coal deliveries were partially offset by a corresponding decrease in revenues from mining operations as discussed above.
  - A $2 million decrease in operation expense as a result of lower employee-related expenses.
  - A $2 million gain on sale of property related to the sale of percentage ownership of Turk Plant to nonaffiliated companies who exercised their participation options.

- Taxes Other Than Income Taxes decreased $2 million primarily due to lower property tax, revenue related taxes and sales and use tax.
- Other Income increased $11 million primarily due to an increase in the equity component of AFUDC as a result of construction at the Turk Plant and Stall Unit and the reapplication of SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009. See "Texas Rate Matters – Texas Restructuring – SPP" section of Note 3.
- Interest Expense increased $1 million primarily due to increased interest on debt of $7 million related to increased construction expenditures which were partially offset by a $6 million increase in the debt component of AFUDC.
- Income Tax Expense increased $9 million primarily due to an increase in pretax book income and state income taxes, partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

SWEPCo's credit ratings as of June 30, 2009 were as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa3	BBB	BBB+

S&P and Moody's have SWEPCo on stable outlook. In July 2009, Fitch changed its rating outlook for SWEPCo from stable to negative due to elevated debt levels to fund Stall Unit and Turk Plant. In 2009, Moody's downgraded SWEPCo to Baa3, reflecting higher business risk associated with the construction of the Turk Plant. If SWEPCo receives further downgrades from any of the rating agencies, its borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Cash flows for the six months ended June 30, 2009 and 2008 were as follows:

	2009	2008
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,910	$ 1,742
Cash Flows from (Used for):		
Operating Activities	222,403	76,537
Investing Activities	(236,343)	(569,109)
Financing Activities	13,541	493,072
Net Increase (Decrease) in Cash and Cash Equivalents	(399)	500
Cash and Cash Equivalents at End of Period	$ 1,511	$ 2,242

Operating Activities

Net Cash Flows from Operating Activities were $222 million in 2009. SWEPCo produced Net Income of $42 million during the period and had noncash items of $72 million for Depreciation and Amortization, $30 million for Deferred Income Taxes, $20 million for Deferred Property Taxes and $19 million for Allowance for Equity Funds Used During Construction. 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 $88 million inflow from Accounts Receivable, Net was primarily due to the receipt of payment for SIA from the AEP East companies. The $64 million inflow from Accrued Taxes, Net was the result of an increase in accruals related to federal and property tax. The $54 million outflow from Other Current Liabilities was due to a decrease in checks outstanding, a refund to wholesale customers for the SIA and payments of employee-related expenses. The $44 million inflow from Fuel Over/Under-Recovery, Net was the result of a decrease in fuel costs in relation to the recovery of these costs from customers. The $23 million inflow from Accounts Payable was primarily due to increases related to customer accounts factored, net.

Net Cash Flows from Operating Activities were $77 million in 2008. SWEPCo produced Net Income of $21 million during the period and had a noncash expense item of $73 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $84 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel costs. The $61 million inflow from Accounts Payable was primarily due to higher fuel related costs. The $32 million inflow from Accounts Receivable, Net was primarily due to the assignment of certain ERCOT contracts to an affiliate company. The $13 million outflow from Accrued Taxes, Net was the result of increased payments related to property and income taxes.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $236 million and $569 million, respectively. Construction Expenditures of $306 million and $266 million in 2009 and 2008, respectively, were primarily related to new generation projects at the Turk Plant and Stall Unit. Proceeds from Sales of Assets in 2009 primarily includes $104 million relating to the sale of a portion of Turk Plant to joint owners. SWEPCo's net increase in loans to the Utility Money Pool during 2009 and 2008 were $32 million and $301 million, respectively. SWEPCo forecasts approximately $457 million of construction expenditures for all of 2009, excluding AFUDC.

Financing Activities

Net Cash Flows from Financing Activities were $14 million during 2009. SWEPCo received a Capital Contribution from Parent of $18 million. SWEPCo had an $8 million inflow from borrowings of Nonaffiliated Short-term Debt. SWEPCo paid $5 million in principal payments for capital lease obligations. SWEPCo had a net decrease of $3 million in borrowings from the Utility Money Pool.

Net Cash Flows from Financing Activities were $493 million during 2008. SWEPCo issued $400 million of Senior Unsecured Notes. SWEPCo received a Capital Contribution from Parent of $100 million.

Financing Activity

Long-term debt issuances and principal payments made during the first six months of 2009 were:

Issuances

None

Principal Payments

Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Nonaffiliated	$ 2,203	4.47	2011

Liquidity

The financial markets remain volatile at both a global and domestic level. The uncertainties in the capital markets could have significant implications on SWEPCo since it relies on continuing access to capital to fund operations and capital expenditures. Management cannot predict the length of time the credit situation will continue or its impact on SWEPCo's operations and ability to issue debt at reasonable interest rates.

SWEPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. SWEPCo will rely upon cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 for additional discussion of liquidity.

Summary Obligation Information

A summary of contractual obligations is included in the 2008 Annual Report and has not changed significantly from year-end.

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, 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 if the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2008 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 beginning on page H-1. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page I-1 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 2008 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 beginning on page I-1 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 SWEPCo's Condensed Consolidated Balance Sheet as of June 30, 2009 and the reasons for changes in total MTM value as compared to December 31, 2008.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
June 30, 2009
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 7,548	$ 156	$ -	$ -	$ 7,704
Noncurrent Assets	755	52	-	-	807
Total MTM Derivative Contract Assets	8,303	208	-	-	8,511
Current Liabilities	5,634	153	76	(145)	5,718
Noncurrent Liabilities	415	-	36	(26)	425
Total MTM Derivative Contract Liabilities	6,049	153	112	(171)	6,143
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,254	$ 55	$ (112)	$ 171	$ 2,368

(a) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2009
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2008	$	2,643
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(666)
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		(35)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		73
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		239
Total MTM Risk Management Contract Net Assets		2,254
Cash Flow Hedge Contracts		55
DETM Assignment (d)		(112)
Collateral Deposits		171
Ending Net Risk Management Assets at June 30, 2009	$	2,368

(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. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(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.
(d) See "Natural Gas Contracts with DETM" section of Note 15 of the 2008 Annual Report.

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

The following table presents 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 (Liabilities)
June 30, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (165)	$ -	$ -	$ -	$ -	$ -	$ (165)
Level 2 (b)	1,050	1,714	(349)	(11)	-	-	2,404
Level 3 (c)	13	2	-	-	-	-	15
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 898	$ 1,716	$ (349)	$ (11)	$ -	$ -	$ 2,254

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1 and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Credit Risk

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

See Note 8 for further information regarding MTM risk management contracts, cash flow hedging, accumulated other comprehensive income, credit risk and collateral triggering events.

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, 2009, a near term typical change in commodity prices is not expected to have a material effect on net income, 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, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$25	$49	$20	$6	$8	$220	$62	$8

Management back-tests its VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Management's back-testing results show that its actual performance exceeded VaR far fewer than once every 20 trading days. As a result, management believes SWEPCo's VaR calculation is conservative.

As SWEPCo's VaR calculation captures recent price moves, management also performs regular stress testing of the portfolio to understand SWEPCo's exposure to extreme price moves. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. Management then researches the underlying positions, price moves and market events that created the most significant exposure.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which SWEPCo's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on SWEPCo's debt outstanding as of June 30, 2009, the estimated EaR on SWEPCo's debt portfolio for the following twelve months was $4.1 million.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended 2009	Three Months Ended 2008	Six Months Ended 2009	Six Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 326,992	$ 397,428	$ 629,375	$ 711,342
Sales to AEP Affiliates	5,706	17,592	14,050	31,184
Lignite Revenues – Nonaffiliated	7,518	8,204	18,238	20,191
Other Revenues	566	393	921	693
TOTAL REVENUES	340,782	423,617	662,584	763,410
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	117,135	147,147	243,450	264,808
Purchased Electricity for Resale	30,339	54,378	54,736	94,648
Purchased Electricity from AEP Affiliates	10,520	51,932	23,530	72,372
Other Operation	59,566	58,757	113,770	122,336
Maintenance	23,314	27,692	50,016	55,160
Depreciation and Amortization	35,559	36,897	72,351	73,033
Taxes Other Than Income Taxes	15,479	15,705	30,868	33,124
TOTAL EXPENSES	291,912	392,508	588,721	715,481
OPERATING INCOME	48,870	31,109	73,863	47,929
Other Income (Expense):				
Interest Income	363	1,540	817	2,417
Allowance for Equity Funds Used During Construction	12,369	2,952	18,774	6,015
Interest Expense	(18,990)	(17,270)	(35,289)	(34,412)
INCOME BEFORE INCOME TAX EXPENSE	42,612	18,331	58,165	21,949
Income Tax Expense	6,834	3,351	10,687	1,364
INCOME BEFORE EXTRAORDINARY LOSS	35,778	14,980	47,478	20,585
EXTRAORDINARY LOSS, NET OF TAX	(5,325)	-	(5,325)	-
NET INCOME	30,453	14,980	42,153	20,585
Less: Net Income Attributable to Noncontrolling Interest	812	899	1,949	1,894
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	29,641	14,081	40,204	18,691
Less: Preferred Stock Dividend Requirements	57	57	114	114
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 29,584	$ 14,024	$ 40,090	$ 18,577

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2007	$ 135,660	$ 330,003	$ 523,731	$ (16,439)	$ 1,687	$ 974,642
EITF 06-10 Adoption, Net of Tax of $622			(1,156)			(1,156)
SFAS 157 Adoption, Net of Tax of $6			10			10
Capital Contribution from Parent		100,000				100,000
Common Stock Dividends – Nonaffiliated					(1,915)	(1,915)
Preferred Stock Dividends			(114)			(114)
SUBTOTAL – EQUITY						1,071,467
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of $89				(172)	7	(165)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $253				471		471
NET INCOME			18,691		1,894	20,585
TOTAL COMPREHENSIVE INCOME						20,891
TOTAL EQUITY – JUNE 30, 2008	$ 135,660	430,003	541,162	(16,140)	1,673	$ 1,092,358
TOTAL EQUITY – DECEMBER 31, 2008	$ 135,660	$ 530,003	$ 615,110	$ (32,120)	$ 276	$ 1,248,929
Capital Contribution from Parent		17,500				17,500
Common Stock Dividends – Nonaffiliated					(1,920)	(1,920)
Preferred Stock Dividends			(114)			(114)
Other Changes in Equity		2,476	(2,476)			-
SUBTOTAL – EQUITY						1,264,395
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $306				568		568
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $8,583				15,939		15,939
NET INCOME			40,204		1,949	42,153
TOTAL COMPREHENSIVE INCOME						58,660
TOTAL EQUITY – JUNE 30, 2009	$ 135,660	$ 549,979	$ 652,724	$ (15,613)	$ 305	$ 1,323,055

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,511	$ 1,910
Advances to Affiliates	31,999	-
Accounts Receivable:		
Customers	54,045	53,506
Affiliated Companies	33,581	121,928
Miscellaneous	11,241	12,052
Allowance for Uncollectible Accounts	(26)	(135)
Total Accounts Receivable	98,841	187,351
Fuel	99,995	100,018
Materials and Supplies	54,040	49,724
Risk Management Assets	7,704	8,185
Regulatory Asset for Under-Recovered Fuel Costs	16,137	75,006
Prepayments and Other Current Assets	31,148	20,147
TOTAL CURRENT ASSETS	341,375	442,341
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,816,300	1,808,482
Transmission	824,083	786,731
Distribution	1,433,405	1,400,952
Other Property, Plant and Equipment	716,560	711,260
Construction Work in Progress	1,000,865	869,103
Total Property, Plant and Equipment	5,791,213	5,576,528
Accumulated Depreciation and Amortization	2,086,162	2,014,154
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,705,051	3,562,374
OTHER NONCURRENT ASSETS		
Regulatory Assets	249,681	210,174
Long-term Risk Management Assets	807	1,500
Deferred Charges and Other Noncurrent Assets	58,062	36,696
TOTAL OTHER NONCURRENT ASSETS	308,550	248,370
TOTAL ASSETS	$ 4,354,976	$ 4,253,085

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 2,526
Accounts Payable:		
General	155,171	133,538
Affiliated Companies	62,199	51,040
Short-term Debt – Nonaffiliated	14,872	7,172
Long-term Debt Due Within One Year – Nonaffiliated	4,406	4,406
Long-term Debt Due Within One Year – Affiliated	50,000	-
Risk Management Liabilities	5,718	6,735
Customer Deposits	39,337	35,622
Accrued Taxes	97,810	33,744
Accrued Interest	33,526	36,647
Provision for Revenue Refund	28,207	54,100
Other Current Liabilities	60,884	102,535
TOTAL CURRENT LIABILITIES	552,130	468,065
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,421,745	1,423,743
Long-term Debt – Affiliated	-	50,000
Long-term Risk Management Liabilities	425	516
Deferred Income Taxes	403,097	403,125
Regulatory Liabilities and Deferred Investment Tax Credits	329,617	335,749
Asset Retirement Obligations	52,885	53,433
Employment Benefits and Pension Obligations	123,532	117,772
Deferred Credits and Other Noncurrent Liabilities	143,793	147,056
TOTAL NONCURRENT LIABILITIES	2,475,094	2,531,394
TOTAL LIABILITIES	3,027,224	2,999,459
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Commitments and Contingencies (Note 4)		
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	549,979	530,003
Retained Earnings	652,724	615,110
Accumulated Other Comprehensive Income (Loss)	(15,613)	(32,120)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,322,750	1,248,653
Noncontrolling Interest	305	276
TOTAL EQUITY	1,323,055	1,248,929
TOTAL LIABILITIES AND EQUITY	$ 4,354,976	$ 4,253,085

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 42,153	$ 20,585
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	72,351	73,033
Deferred Income Taxes	(29,774)	28,256
Extraordinary Loss, Net of Tax	5,325	-
Allowance for Equity Funds Used During Construction	(18,774)	(6,015)
Mark-to-Market of Risk Management Contracts	279	1,541
Deferred Property Taxes	(19,862)	(19,866)
Change in Other Noncurrent Assets	5,731	3,434
Change in Other Noncurrent Liabilities	2,222	(17,085)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	88,457	31,975
Fuel, Materials and Supplies	(4,293)	(14,978)
Accounts Payable	22,698	60,552
Accrued Taxes, Net	64,066	(12,503)
Fuel Over/Under-Recovery, Net	44,125	(84,206)
Other Current Assets	1,902	7,296
Other Current Liabilities	(54,203)	4,518
Net Cash Flows from Operating Activities	222,403	76,537
INVESTING ACTIVITIES		
Construction Expenditures	(305,886)	(266,145)
Change in Advances to Affiliates, Net	(31,999)	(300,525)
Proceeds from Sales of Assets	105,453	141
Other Investing Activities	(3,911)	(2,580)
Net Cash Flows Used for Investing Activities	(236,343)	(569,109)
FINANCING ACTIVITIES		
Capital Contribution from Parent	17,500	100,000
Issuance of Long-term Debt – Nonaffiliated	(15)	396,446
Change in Short-term Debt, Net – Nonaffiliated	7,700	6,754
Change in Advances from Affiliates, Net	(2,526)	(1,565)
Retirement of Long-term Debt – Nonaffiliated	(2,203)	(3,703)
Principal Payments for Capital Lease Obligations	(5,266)	(2,831)
Dividends Paid on Common Stock – Nonaffiliated	(1,645)	(1,915)
Dividends Paid on Cumulative Preferred Stock	(114)	(114)
Other Financing Activities	110	-
Net Cash Flows from Financing Activities	13,541	493,072
Net Increase (Decrease) in Cash and Cash Equivalents	(399)	500
Cash and Cash Equivalents at Beginning of Period	1,910	1,742
Cash and Cash Equivalents at End of Period	$ 1,511	$ 2,242
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 50,711	$ 19,848
Net Cash Paid for Income Taxes	3,816	10,276
Noncash Acquisitions Under Capital Leases	1,751	17,236
Construction Expenditures Included in Accounts Payable at June 30,	86,920	68,670

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page H-1.

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. The footnotes begin on page H-1.

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	SWEPCo
6.	Benefit Plans	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
7.	Business Segments	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
8.	Derivatives and Hedging	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
9.	Fair Value Measurements	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
10.	Income Taxes	APCo, CSPCo, I&M, OPCo, PSO, SWEPCo
11.	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 GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. Net income for the three and six months ended June 30, 2009 are not necessarily indicative of results that may be expected for the year ending December 31, 2009. Management reviewed subsequent events through the Registrant Subsidiaries' Form 10-Q issuance date of August 4, 2009. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2008 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2008 as filed with the SEC on February 27, 2009.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether they are the primary beneficiary of a VIE, each Registrant Subsidiary considers factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine and DHLC. OPCo is the primary beneficiary of JMG. APCo, CSPCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and CSPCo each hold a significant variable interest in AEGCo.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. Based on these facts, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended June 30, 2009 and 2008 were $25 million and $28 million, respectively, and for the six months ended June 30, 2009 and 2008 were $61 million and $48 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's Condensed Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHLC. SWEPCo's total billings from DHLC for both the three months ended June 30, 2009 and 2008 were $8 million and for the six months ended June 30, 2009 and 2008 were $18 million and $20 million, respectively. See the tables below for the classification of DHLC assets and liabilities on SWEPCo's Condensed Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
June 30, 2009
(in millions)

	Sabine	DHLC
ASSETS		
Current Assets	$ 37	$ 15
Net Property, Plant and Equipment	125	30
Other Noncurrent Assets	30	12
Total Assets	$ 192	$ 57
LIABILITIES AND EQUITY		
Current Liabilities	$ 40	$ 12
Noncurrent Liabilities	152	42
Equity	-	3
Total Liabilities and Equity	$ 192	$ 57

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
December 31, 2008
(in millions)

	Sabine	DHLC
ASSETS		
Current Assets	$ 33	$ 22
Net Property, Plant and Equipment	117	33
Other Noncurrent Assets	24	11
Total Assets	$ 174	$ 66
LIABILITIES AND EQUITY		
Current Liabilities	$ 32	$ 18
Noncurrent Liabilities	142	44
Equity	-	4
Total Liabilities and Equity	$ 174	$ 66

OPCo has a lease agreement with JMG to finance OPCo's FGD system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments are the only form of repayment associated with JMG's debt obligations even though OPCo does not guarantee JMG's debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. As of June 30, 2009, OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded that OPCo is the primary beneficiary and is required to consolidate JMG. OPCo's total billings from JMG for the three months ended June 30, 2009 and 2008 were $31 million and $13 million, respectively, and for the six months ended June 30, 2009 and 2008 were $49 million and $26 million, respectively. See the tables below for the classification of JMG's assets and liabilities on OPCo's Condensed Consolidated Balance Sheets.

In April 2009, OPCo paid JMG $58 million which was used to retire certain long-term debt of JMG. While this payment was not contractually required, OPCo made this payment in anticipation of purchasing the outstanding equity of JMG.

In July 2009, OPCo purchased all of the outstanding equity ownership of JMG for $28 million. AEP's intent is to dissolve JMG. The assets and liabilities of JMG will remain incorporated with OPCo's business.

The balances below represent the assets and liabilities of the VIE that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

OHIO POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITY
June 30, 2009
(in millions)

ASSETS	JMG
Current Assets	$ 16
Net Property, Plant and Equipment	413
Other Noncurrent Assets	1
Total Assets	$ 430

LIABILITIES AND EQUITY	JMG
Current Liabilities	$ 150
Noncurrent Liabilities	262
Equity	18
Total Liabilities and Equity	$ 430

OHIO POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITY
December 31, 2008
(in millions)

ASSETS	JMG
Current Assets	$ 11
Net Property, Plant and Equipment	423
Other Noncurrent Assets	1
Total Assets	$ 435

LIABILITIES AND EQUITY	JMG
Current Liabilities	$ 161
Noncurrent Liabilities	257
Equity	17
Total Liabilities and Equity	$ 435

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. No AEP subsidiary has provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations by cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP's subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. All Registrant Subsidiaries are considered to have a significant interest in the variability in AEPSC due to their activity in AEPSC's cost reimbursement structure. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2009	2008	2009	2008
	(in millions)			
APCo	$ 46	$ 53	$ 97	$ 117
CSPCo	31	31	60	63
I&M	32	31	61	72
OPCo	46	47	87	99
PSO	21	27	43	58
SWEPCo	31	31	60	66

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	June 30, 2009		December 31, 2008	
	As Reported in the Balance Sheet	Maximum Exposure	As Reported in the Balance Sheet	Maximum Exposure
Company	(in millions)			
APCo	$ 17	$ 17	$ 27	$ 27
CSPCo	12	12	15	15
I&M	12	12	14	14
OPCo	18	18	21	21
PSO	8	8	10	10
SWEPCo	12	12	14	14

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. In May 2007, AEGCo began leasing the Lawrenceburg Generating Station to CSPCo. AEP guarantees all the debt obligations of AEGCo. I&M and CSPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and CSPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. Due to the nature of the AEP Power Pool, there is a sharing of the cost of Rockport and Lawrenceburg Plants such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport or Lawrenceburg Plants. In the event AEGCo would require financing or other support outside the billings to I&M, CSPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13 in the 2008 Annual Report.

Total billings from AEGCo were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Company	(in millions)			
CSPCo	$ 15	$ 25	$ 32	$ 49
I&M	60	57	123	116

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

	June 30, 2009		December 31, 2008	
	As Reported in the Consolidated Balance Sheet	Maximum Exposure	As Reported in the Consolidated Balance Sheet	Maximum Exposure
Company	(in millions)			
CSPCo	$ 6	$ 6	$ 5	$ 5
I&M	20	20	23	23

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrant Subsidiaries recognize the revenues on their statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

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. The AEP East companies then purchase power from PJM to supply their customers. Generally, these power sales and purchases are reported on a net basis as revenues on the AEP East companies' statements of income. However, in 2009, there were times when the AEP East companies were purchasers of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on the AEP East companies' statements of income. Other RTOs in which the AEP East companies operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, CSPCo and OPCo revised book depreciation rates for generating plants consistent with a recently completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. In comparing 2009 and 2008, the change in depreciation rates resulted in a net increase (decrease) in deprecation expense of:

	Total Depreciation Expense Variance	
	Three Months Ended June 30, 2009/2008	Six Months Ended June 30, 2009/2008
	(in thousands)	
CSPCo	$ (4,407)	$ (8,674)
OPCo	17,584	34,230

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of final pronouncements issued or implemented in 2009 and standards issued but not implemented that management has determined relate to the Registrant Subsidiaries' operations.

Pronouncements Adopted During 2009

The following standards were effective during the first six months of 2009. Consequently, the financial statements and footnotes reflect their impact.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. The Registrant Subsidiaries do not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

The Registrant Subsidiaries adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. The Registrant Subsidiaries had no business combinations in 2009. The Registrant Subsidiaries will apply it to any future business combinations.

SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

The Registrant Subsidiaries adopted SFAS 160 effective January 1, 2009 and retrospectively applied the standard to prior periods. The adoption of SFAS 160 had no impact on APCo, CSPCo, I&M and PSO. The retrospective application of this standard impacted OPCo and SWEPCo as follows:

OPCo:

- Reclassifies Interest Expense of $415 thousand and $878 thousand for the three and six months ended June 30, 2008 as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to OPCo Common Shareholder in its Condensed Consolidated Statements of Income.
- Reclassifies Minority Interest of $16.8 million as of December 31, 2008 as Noncontrolling Interest in Total Equity on its Condensed Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interest in its Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $878 thousand for the six months ended June 30, 2008 from Operating Activities to Financing Activities in the Condensed Consolidated Statements of Cash Flows.

SWEPCo:

- Reclassifies Minority Interest Expense of $899 thousand and $1.9 million for the three and six months ended June 30, 2008 as Net Income Attributable to Noncontrolling Interest below Net Income in the presentation of Earnings Attributable to SWEPCo Common Shareholder in its Condensed Consolidated Statements of Income.
- Reclassifies Minority Interest of $276 thousand as of December 31, 2008 as Noncontrolling Interest in Total Equity on its Condensed Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interest in the Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $1.9 million for the six months ended June 30, 2008 from Operating Activities to Financing Activities in the Condensed Consolidated Statements of Cash Flows.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

The Registrant Subsidiaries adopted SFAS 161 effective January 1, 2009. This standard increased the disclosures related to derivative instruments and hedging activities. See Note 8.

SFAS 165 "Subsequent Events" (SFAS 165)

In May 2009, the FASB issued SFAS 165 incorporating guidance on subsequent events into authoritative accounting literature and clarifying the time following the balance sheet date which management reviewed for event and transactions that require disclosure in the financial statements.

The Registrant Subsidiaries adopted this standard effective second quarter of 2009. The standard increased disclosure by requiring disclosure of the date through which subsequent events have been reviewed. The standard did not change management's procedures for reviewing subsequent events.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

The Registrant Subsidiaries adopted EITF 08-5 effective January 1, 2009. With the adoption of FSP SFAS 107-1 and APB 28-1, it is applied to the fair value of long-term debt. The application of this standard had an immaterial effect on the fair value of debt outstanding.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

The Registrant Subsidiaries adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

The Registrant Subsidiaries adopted the standard effective second quarter of 2009. This standard increased the disclosure requirements related to financial instruments. See "Fair Value Measurements of Long-term Debt" section of Note 9.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

The Registrant Subsidiaries adopted the standard effective second quarter of 2009. The adoption had no impact on APCo, CSPCo, OPCo, PSO and SWEPCo. For I&M, the adoption had no impact on its financial statements but increased disclosure requirements related to financial instruments. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 9.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

The Registrant Subsidiaries adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued SFAS 157-2 which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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.

The Registrant Subsidiaries adopted SFAS 157-2 effective January 1, 2009. The Registrant Subsidiaries will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analyses related to long-lived assets, equity investments, goodwill and intangibles. The Registrant Subsidiaries did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first six months of 2009.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

The Registrant Subsidiaries adopted the standard effective second quarter of 2009. This standard had no impact on the financial statements but increased the disclosure requirements. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 9.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts will be disclosed at that time.

SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)

In June 2009, the FASB issued SFAS 166 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

SFAS 166 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Although management has not completed an analysis, management does not expect this standard to have a material impact on the financial statements. The Registrant Subsidiaries will adopt SFAS 166 effective January 1, 2010.

SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167)

In June 2009, the FASB issued SFAS 167 amending the analysis an entity must perform to determine if it has a controlling interest in a variable interest entity (VIE). This new guidance provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
- The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The standard also requires separate presentation on the face of the statement of financial position for assets which can only be used to settle obligations of a consolidated VIE and liabilities for which creditors do not have recourse to the general credit of the primary beneficiary.

SFAS 167 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Management continues to review the impact of the changes in the consolidation guidance on the financial statements. This standard will increase disclosure requirements related to transactions with VIEs and change the presentation of consolidated VIE's assets and liabilities on the Registrant Subsidiaries' balance sheets. The Registrant Subsidiaries will adopt SFAS 167 effective January 1, 2010.

SFAS 168 "The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles" (SFAS 168)

In June 2009, the FASB issued SFAS 168 establishing the FASB Accounting Standards Codification™ as the authoritative source of accounting principles for preparation of financial statements and reporting in conformity with GAAP by nongovernmental entities.

This standard is effective for interim and annual reporting periods ending after September 15, 2009. It requires an update of all references to authoritative accounting literature. The Registrant Subsidiaries will adopt SFAS 168 effective third quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policies including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. The Registrant Subsidiaries will adopt the standard effective for the 2009 Annual Report.

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 the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, leases, insurance, hedge accounting, discontinued operations and income tax. 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 net income and financial position.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo returned to cost-based regulation and re-applied SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of SFAS 71 regulatory accounting resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. RATE MATTERS

The Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2008 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2009 and updates the 2008 Annual Report.

Ohio Rate Matters

Ohio Electric Security Plan Filings – Affecting CSPCo and OPCo

In July 2008, as required by the 2008 amendments to the Ohio restructuring legislation, CSPCo and OPCo filed ESPs with the PUCO to establish standard service offer rates. In March 2009, the PUCO issued an order, which was amended by a rehearing entry in July 2009, that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The capped increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. CSPCo and OPCo implemented rates for the April 2009 billing cycle. In its July 2009 rehearing entry, the PUCO required CSPCo and OPCo to reduce rates implemented in April 2009 by $22 million and $27 million, respectively, on an annualized basis. CSPCo and OPCo are collecting the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

As of June 30, 2009, the recognized revenues and the FAC deferrals were adjusted to reflect the PUCO's July 2009 rehearing entry, which among other things, reversed the prior authorization to recover the cost of CSPCo's recently acquired Waterford and Darby Plants. In July 2009, CSPCo filed an application for rehearing with the PUCO seeking authorization to sell or transfer the Waterford and Darby Plants. The FAC deferrals after adjustment at June 30, 2009 were $34 million and $140 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales.

The PUCO also addressed several additional matters which are described below:

- CSPCo should attempt to mitigate the costs of its gridSMART advanced metering proposal that will affect portions of its service territory by seeking matching funds under the American Recovery and Reinvestment Act of 2009. CSPCo plans to file for these matching federal funds during the third quarter of 2009. As a result, a rider was established to recover 50% or $32 million of the projected $64 million revenue requirement related to gridSMART.

- CSPCo and OPCo can recover their incremental carrying costs related to environmental investments made from 2001 through 2008 that are not reflected in existing rates. Future recovery during the ESP period of incremental carrying charges on environmental expenditures incurred beginning in 2009 may be requested in annual filings.

- CSPCo's and OPCo's Provider of Last Resort revenues were increased by $97 million and $55 million, respectively, to compensate for the risk of customers changing electric suppliers during the ESP period.

- CSPCo and OPCo must fund a combined minimum of $15 million in costs over the ESP period for low-income, at-risk customer programs. In March 2009, this funding obligation was recognized as a liability and charged to Other Operation expense. At June 30, 2009, CSPCo's and OPCo's liability balance was $6.5 million each.

Consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET) that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings. This is determined by measuring whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, which have comparable business and financial risk. In the March 2009 order, the PUCO determined that off-system sales margins and FAC deferral credits and associated costs should be excluded from the SEET methodology. The July 2009 PUCO rehearing entry deferred those issues to the SEET workshop. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the PUCO must require that the excess amount be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until a SEET filing is made in 2010 and the PUCO issues an order thereon.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP and not to the effective date of tariffs and clarified the tariffs were not retroactive. In the rehearing entry, the PUCO reaffirmed its holding that it had not authorized retroactive rates.

In April 2009, certain intervenors filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases. In May 2009, CSPCo, OPCo and the PUCO filed a motion to dismiss the writ of prohibition. In June 2009, the Ohio Supreme Court dismissed the writ of prohibition.

In June 2009, intervenors filed a motion in the ESP proceeding with the PUCO requesting CSPCo and OPCo to refund deferrals allegedly collected by CSPCo and OPCo which were created by the PUCO's approval of a temporary special arrangement between CSPCo, OPCo and Ormet, a large industrial customer. In addition, the intervenors requested that the PUCO prevent CSPCo and OPCo from collecting these revenues in the future. In June 2009, CSPCo and OPCo filed its response regarding the motion to refund amounts allegedly collected and to prevent future collections. The CSPCo and OPCo response noted that the difference in the amount deferred between the PUCO-determined market price for 2008 and the rate paid by Ormet was not collected, but instead was deferred, with PUCO authorization, as a regulatory asset for future recovery. In the rehearing entry, the PUCO did not order an adjustment to rates based on this issue. See "Ormet" section below.

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. In June 2006, the PUCO issued an order approving a tariff to allow CSPCo and OPCo to recover pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period, CSPCo and OPCo each collected $12 million in pre-construction costs and incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million.

The June 2006 order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all pre-construction cost recoveries associated with items that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest.

In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest. In October 2008, CSPCo and OPCo filed a respond with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that CSPCo and OPCo have not commenced construction of the IGCC plant and CSPCo and OPCo believe there exist real statutory barriers to the construction of any new base load generation in Ohio, including an IGCC plant. The statement also indicated that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in the commencement of construction on a continuous course by that time.

Management continues to pursue the ultimate construction of an IGCC plant in Ohio although CSPCo and OPCo will not start construction of an IGCC plant until sufficient assurance of regulatory cost recovery exists. If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in another jurisdiction, it would have an adverse effect on future net income and cash flows. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

Ormet – Affecting CSPCo and OPCo

In December 2008, CSPCo, OPCo and Ormet, a large aluminum company currently operating at a reduced load of approximately 400 MW, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The arrangement would be effective January 1, 2009 and remain in effect and expire upon the later of the effective date of CSPCo's and OPCo's new ESP rates and the effective date of a new arrangement between Ormet and CSPCo/OPCo as approved by the PUCO. Under the interim arrangement, Ormet would pay the then-current applicable generation tariff rates and riders and CSPCo and OPCo would defer as a regulatory asset, beginning in 2009, the difference between the PUCO-approved 2008 market price of $53.03 per MWH and the applicable generation tariff rates and riders. CSPCo and OPCo proposed to recover the deferral through the FAC mechanism they proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement. In February 2009, an intervenor filed an application for rehearing of the PUCO's interim arrangement approval. In March 2009, the PUCO granted that application for further consideration of the matters specified in the rehearing application. In the PUCO's July 2009 order discussed below, CSPCo and OPCo were directed to file an application to recover the appropriate amounts of the deferrals under the interim agreement and for the remainder of 2009.

In February 2009, as amended in April 2009, Ormet filed an application with the PUCO for approval of a proposed Ormet power contract for 2009 through 2018. Ormet proposed to pay varying amounts based on certain conditions, including the price of aluminum and the level of production. The difference between the amounts paid by Ormet and the otherwise applicable PUCO ESP tariff rate would be either collected from or refunded to CSPCo's and OPCo's retail customers.

In March 2009, the PUCO issued an order in the ESP filings which included approval of a FAC for the ESP period. The approval of an ESP FAC, together with the January 2009 PUCO approval of the Ormet interim arrangement, provided the basis to record regulatory assets of $18 million and $14 million for CSPCo and OPCo, respectively, for the differential in the approved market price of $53.03 versus the rate paid by Ormet during the first six months of 2009. These amounts are included in CSPCo's and OPCo's FAC phase-in deferral balance of $34 million and $140 million, respectively. See "Ohio Electric Security Plan Filings" section above. The pricing and deferral authority under the PUCO's January 2009 approval of the interim arrangement will continue until the 2009-2018 power contract becomes effective.

In May 2009, intervenors filed a motion with the PUCO that contends CSPCo and OPCo should be charging Ormet the new ESP rate and that no additional deferrals between the approved market price and the rate paid by Ormet should be calculated and recovered through the FAC since Ormet will be paying the new ESP rate. In May 2009, CSPCo and OPCo filed a Memorandum Contra recommending the PUCO deny the motion to cease additional deferrals. In June 2009, intervenors filed a motion with the PUCO related to Ormet in the ESP proceeding. See "Ohio Electric Security Plan Filings" section above.

In July 2009, the PUCO approved Ormet's application for a power contract through 2018 with several modifications. As modified by the PUCO, rates billed to Ormet by CSPCo and OPCo for the balance of 2009 would reflect an annual averaged rate of $38 per MWH for the periods Ormet was in full production and $35 and $34 per MWH at certain curtailed production levels. These rates are contingent upon Ormet maintaining its employment levels at 900 employees for 2009. The PUCO authorized CSPCo and OPCo to defer foregone revenue amounts (the difference between CSPCo's and OPCo's tariff rate and the rate paid by Ormet) created by the blended rate for the remainder of 2009. For 2010 through 2018, the PUCO approved the linkage of Ormet's rate to the price of aluminum but modified the agreement to include a maximum electric rate discount for Ormet that declines over time to zero in 2018 and a maximum amount of revenue foregone that ratepayers will be expected to pay via a rider in any given year. To the extent the discount exceeds the amount collectible from ratepayers, the difference can be deferred, with a long-term debt carrying charge, for future recovery. In addition, this rate is based upon Ormet maintaining at least 650 employees. For every 50 employees below that level, Ormet's maximum electric rate discount will be reduced. In July 2009, Ormet announced that it will substantially curtail operations starting in September 2009.

Hurricane Ike – Affecting CSPCo and OPCo

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. Under the RSP, which was effective in 2008, CSPCo and OPCo could seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively, for the expected recovery of the storm restoration costs. In December 2008, the PUCO approved these regulatory assets along with a long-term debt only carrying cost on these regulatory assets. In its order approving the deferrals, the PUCO stated that the mechanism for recovery would be determined in CSPCo's and OPCo's next distribution rate filing. At June 30, 2009, CSPCo and OPCo have accrued regulatory assets of $18 million and $10 million, respectively, including the approved long-term debt only carrying costs.

Texas Rate Matters

Texas Restructuring – SPP – Affecting SWEPCo

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo returned to cost-based regulation and re-applied SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of SFAS 71 regulatory accounting resulted in an $8 million ($5 million, net of tax) extraordinary loss.

In addition, effective April 2009, the generation portion of SWEPCo's Texas retail jurisdiction began accruing AFUDC (debt and equity return) instead of capitalized interest on its eligible construction balances including the Stall Unit and the Turk Plant. The accrual of AFUDC increased second quarter of 2009 net income by approximately $3 million using the last PUCT-approved return on equity rate.

Stall Unit – Affecting SWEPCo

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

Turk Plant – Affecting SWEPCo

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

Virginia Rate Matters

Virginia E&R Costs Recovery Filing – Affecting APCo

Due to the recovery provisions in Virginia law, APCo has been deferring incremental E&R costs as incurred, excluding the equity return on in-service capital investments, pending future recovery. In October 2008, the Virginia SCC approved a stipulation agreement to recover $61 million of incremental E&R costs incurred from October 2006 to December 2007 through a surcharge in 2009 which will have a favorable effect on cash flows of $61 million and on net income for the previously unrecognized equity portion of the carrying costs of approximately $11 million.

The Virginia E&R cost recovery mechanism under Virginia law ceased effective with costs incurred through December 2008. However, the 2007 amendments to Virginia's electric utility restructuring law provide for a rate adjustment clause to be requested in 2009 to recover incremental E&R costs incurred through December 2008. Under this amendment, APCo filed a request, in May 2009, to recover its unrecovered 2008 incremental deferred E&R costs plus its 2008 equity costs on in-service E&R capital investments. The hearing is scheduled to begin in October 2009.

As of June 30, 2009, APCo has $99 million of deferred Virginia incremental E&R costs (excluding $19 million of unrecognized equity carrying costs). The $99 million consists of $6 million of over-recovered costs collected under the 2008 surcharge, $25 million approved by the Virginia SCC related to the 2009 surcharge and $80 million, representing costs deferred during 2008, which were included in the May 2009 E&R filing for collection in 2010.

If the Virginia SCC were to disallow a material portion of APCo's 2008 deferred incremental E&R costs, it would have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant – Affecting APCo

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

In June 2007, APCo sought pre-approval from the WVPSC for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and 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. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with the proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo's requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. Various parties, including APCo, filed comments but the WVPSC has not taken any action.

Through June 30, 2009, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010.

Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs, which if not recoverable, would have an adverse effect on future net income and cash flows.

Mountaineer Carbon Capture Project – Affecting APCo

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO_2 capture demonstration facility. APCo and Alstom will each own part of the CO_2 capture facility. APCo will also construct and own the necessary facilities to store the CO_2. RWE AG, a German electric power and natural gas public utility, is participating in the project and is providing some funding to offset APCo's costs. APCo's estimated cost for its share of the constructed facilities is $72 million. Through June 30, 2009, APCo incurred $59 million in capitalized project costs which are included in Regulatory Assets. In May 2009, the West Virginia Department of Environmental Protection issued a permit to inject CO_2 that requires, among other items, that APCo monitor the wells for at least 20 years following the cessation of CO_2 injection. APCo plans to start injecting CO_2 in September 2009 which will result, at that time, in an asset retirement obligation and a regulatory asset at its net present value preliminary estimated to be approximately $25 million.

APCo currently earns a return on the Virginia portion of the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on the estimated September 2009 in-service Virginia jurisdictional share of its CO_2 capture and storage project costs including the related asset retirement obligation expenses. See the "Virginia Base Rate Filing" section below. Based on the favorable treatment related to the CO_2 capture demonstration facility in the last Virginia base rate case, management is deferring the carbon capture expense as a regulatory asset for future recovery. APCo plans to seek recovery of the West Virginia jurisdictional costs in its next West Virginia base rate filing which is expected to be filed in late 2009. If the deferred project costs are disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.

Virginia Base Rate Filing – Affecting APCo

The 2007 amendments to Virginia's electric utility restructuring law require that each investor-owned utility, such as APCo, file a base rate case with the Virginia SCC in 2009 in which the Virginia SCC will determine fair rates of return on common equity (ROE) for the generation and distribution services of the utility. In July 2009, APCo filed a base rate case with the Virginia SCC requesting an increase in the generation and distribution portions of base rates of $169 million annually based on a 2008 test year, as adjusted, and a 13.35% ROE inclusive of a requested 0.85% ROE performance incentive increase as permitted by law. The recovery of APCo's transmission service costs in Virginia was requested in a separate and simultaneous transmission rate adjustment clause filing. See the "Rate Adjustment Clauses" section below. The new generation and distribution base rates will be effective, subject to refund, no later than December 2009. In July 2009, APCo filed a motion with the Virginia SCC requesting permission to file, in August 2009, supplemental schedules and testimony reflecting a recent Virginia SCC's order in an unaffiliated utility's base rate case concerning the appropriate capital structure to be used in the determination of the revenue requirement.

Rate Adjustment Clauses – Affecting APCo

In 2007, the Virginia law governing the regulation of electric utility service was amended to, among other items, provide for rate adjustment clauses (RAC) beginning in January 2009 for the timely and current recovery of costs of (a) transmission services billed by an RTO, (b) demand side management and energy efficiency programs, (c) renewable energy programs, (d) environmental compliance projects and (e) new generation facilities including major unit modifications. In July 2009, APCo filed for approval of a transmission RAC simultaneous with the 2009 base rate case filing in which the Virginia jurisdictional share of transmission costs was requested for recovery through the RAC instead of through base rates. The transmission filing requested an annual increase of $24 million to be effective mid-December 2009. See the "Virginia Base Rate Filing" section above. Also, APCo plans to file for approval of an environmental RAC no later than the first quarter of 2010 to recover any unrecovered environmental costs incurred after December 2008. In accordance with Virginia law, APCo is deferring any incremental transmission and environmental costs incurred after December 2008 that are not being recovered in current revenues. As of June 30, 2009, APCo has deferred $8 million of environmental costs (excluding $1 million of unrecognized equity carrying costs) to be recovered in an environmental RAC and $6 million of transmission costs to be recovered in a 2010 transmission RAC filing. Management is evaluating whether to make other RAC filings at this time. If the Virginia SCC were to disallow a portion of APCo's deferred RAC costs, it would have an adverse effect on future net income and cash flows.

Virginia Fuel Factor Proceeding – Affecting APCo

In May 2009, APCo filed an application with the Virginia SCC to increase its fuel adjustment charge by approximately $227 million from July 2009 through August 2010. The $227 million proposed increase related to a $104 million projected under-recovery balance of fuel costs as of June 30, 2009 and $123 million of projected fuel costs for the period July 2009 through August 2010. APCo's actual under-recovered fuel balance at June 30, 2009 was $93 million. Due to the significance of the estimated required increase in fuel rates, APCo's application proposed an alternative method of collection of actual incurred fuel costs. The proposed alternative would allow APCo to recover 100% of the $104 million prior period under-recovery deferral and 50% of the $123 million increase from July 2009 through August 2010 with recovery of any remaining actual under-recovered fuel costs in APCo's next fuel factor proceeding from September 2010 through August 2011. In May 2009, the Virginia SCC ordered that neither of APCo's proposed fuel factors shall become effective, pending further review by the Virginia SCC. On August 3, 2009, the Virginia SCC issued an order. Management is presently reviewing the order, which provided for a $130 million fuel revenue increase, effective August 10, 2009. Management believes that full recovery of the $93 million under-recovered fuel balance at June 30, 2009 is probable. Management also believes that the reduction in revenues from the requested amount represents a decrease in projected fuel costs to be recovered through the approved fuel factor. Such decrease should be recoverable, if necessary, either in APCo's next fuel factor proceeding for the period September 2010 through August 2011 or through other statutory mechanisms.

<u>West Virginia Rate Matters</u>

APCo's 2009 Expanded Net Energy Cost (ENEC) Filing – Affecting APCo

In March 2009, APCo filed an annual ENEC filing with the WVPSC for an increase of approximately $398 million for incremental fuel, purchased power and environmental compliance project expenses, to become effective July 2009. Within the filing, APCo requested the WVPSC to allow APCo to temporarily adopt a modified ENEC mechanism due to the distressed economy and the significance of the projected required increase. The proposed modified ENEC mechanism provides that the ENEC rate increase be phased-in with unrecovered amounts deferred for future recovery over a five-year period beginning in July 2009. The mechanism also extends cost projections out for a period of three years through June 30, 2012 and provides for three annual increases to recover projected future ENEC cost increases as well as the phase-in deferrals. APCo is also requesting that deferred amounts that exceed the deferred amounts that would have otherwise existed under the traditional ENEC mechanism be subject to a carrying charge based upon APCo's weighted average cost of capital. As filed, the modified ENEC mechanism would produce three annual increases, based upon projected fuel costs and including carrying charges, of $170 million, $149 million and $155 million, effective July 2009, 2010 and 2011, respectively.

In March 2009, the WVPSC issued an order suspending the modified ENEC rate increase request until December 2009. In April 2009, APCo filed a motion for approval of an interim rate increase of $162 million, effective July 2009 and subject to refund pending the final adjudication of the ENEC by December 2009. In April 2009, the WVPSC granted intervention to several parties and heard oral arguments from APCo and intervenors on the requested interim ENEC filing. In June 2009, the WVPSC denied APCo's motion for an interim rate increase.

In May 2009, various intervenors submitted testimony supporting adjustments to APCo's actual and projected ENEC costs. The intervenors also proposed alternative rate phase-in plans ranging from three to five years. Specifically, the WVPSC staff and the West Virginia Consumer Advocate recommended a total increase of $338 million and $294 million, respectively, with $119 million and $117 million, respectively, being collected during the first year and suggested that the remaining rate increases for future years be determined in subsequent ENEC filings. In June 2009, APCo filed rebuttal testimony. In the rebuttal testimony, APCo accepted certain intervenor adjustments and reduced the requested overall increase to $358 million with a proposed first-year increase of $144 million. The primary difference between the intervenors' $117 million first-year increase and APCo's $144 million first-year increase is the intervenors' proposed disallowance of up to $32 million of actual and projected coal costs.

APCo expects a decision from the WVPSC on the 2009 ENEC filing during the third quarter of 2009. If the WVPSC were to disallow a portion of APCo's requested increase, it could have an adverse effect on future net income and cash flows.

APCo's Filings for an IGCC Plant – Affecting APCo

See "APCo's Filings for an IGCC Plant" section within "Virginia Rate Matters" for disclosure.

Mountaineer Carbon Capture Project – Affecting APCo

See "Mountaineer Carbon Capture Project" section within "Virginia Rate Matters" for disclosure.

Indiana Rate Matters

Indiana Base Rate Filing – Affecting I&M

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. In addition, I&M proposed to share with customers, through a proposed tracker, 50% of its off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement incorporated the $69 million annual reduction in revenues from the depreciation rate reduction in the development of the agreed to revenue increase of $44 million including a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue for PJM, net emission allowance and demand side management (DSM) costs. The agreement also establishes an off-system sales sharing mechanism and other provisions which include continued funding for the eventual decommissioning of the Cook Plant.

In March 2009, the IURC approved the settlement agreement, with modifications, that provides for an annual increase in revenues of $42 million including a $19 million increase in revenue from base rates, net of the depreciation rate reduction, and a $23 million increase in tracker revenue. The IURC order removed base rate recovery of the DSM costs but established a tracker with an initial zero amount for DSM costs and required I&M to collaborate with other parties regarding future I&M DSM programs, adjusted the sharing of off-system sales margins to 50% above $37.5 million included in base rates and approved the recovery of $7.3 million of previously expensed NSR and OPEB costs which favorably affected first quarter of 2009 net income. In addition, the IURC order requires I&M to review and file a final report by December 2009 on the effectiveness of the Interconnection Agreement including I&M's relationship with PJM. The new rates were implemented in March 2009.

Rockport and Tanners Creek Plants Environmental Facilities – Affecting I&M

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NO_x and mercury from its existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek Plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport Plant. I&M is requesting to depreciate the ACI systems over an accelerated 10-year period and the SNCR systems over the 11-year remaining useful life of the Tanners Creek generating units.

I&M's petition also requested the IURC to approve a rate adjustment mechanism for unrecovered carrying costs during the remaining construction period of these environmental facilities and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the facilities are placed in service. I&M also requested the IURC to authorize the deferral of the remaining construction period carrying costs and any in-service cost of service for these facilities until such costs are recognized in the requested rate adjustment mechanism. Through June 30, 2009, I&M incurred $11 million and $8 million in capitalized facilities cost related to the Rockport and Tanners Creek Plants, respectively, which are included in CWIP. Since the Indiana base rate order included recovery of emission allowance costs, that portion of the cost of service of these facilities will not be included in this requested rate adjustment mechanism.

In May 2009, a settlement agreement (settlement) was filed with the IURC recommending approval of a CPCN and a rider to recover a weighted average cost of capital on I&M's investment in the SNCR system and the ACI system at December 31, 2008, plus future depreciation and operation and maintenance costs. The settlement will allow I&M to file subsequent requests in six month intervals to update the rider for additional investments in the SNCR systems and the ACI systems and for true-ups of the rider revenues to actual costs. In June 2009, the IURC approved the settlement which will result in an annualized increase in rates of $8 million effective August 1, 2009.

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown) – Affecting I&M

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for the period of April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of increased coal prices, the shutdown of the Cook Plant Unit 1 (Unit 1) due to turbine vibrations and a projection for the future period of fuel costs including Unit 1 shutdown replacement power costs. The filing also included an adjustment, beginning coincident with the receipt of insurance proceeds in mid-December 2008, to eliminate the incremental fuel cost of replacement power post mid-December 2008 with a portion of the insurance proceeds from the Unit 1 accidental outage policy. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. I&M reached an agreement in February 2009 with intervenors, which was approved by the IURC in March 2009, to collect the under-recovery over twelve months instead of over six months as proposed. Under the agreement, the fuel factor was placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown, the use of the insurance proceeds and I&M's fuel procurement practices. The order provided for the shutdown issues to be resolved subsequent to the date Unit 1 returns to service, which if temporary repairs are successful, could occur as early as October 2009. Consistent with the March 2009 IURC order, I&M made its semi-annual fuel filing in July 2009 requesting an increase of approximately $4 million for the period October 2009 through March 2010. The projected fuel costs for the period included the second half of the under-recovered balance approved in the March 2009 order plus recovery of a $12 million under-recovered balance from the reconciliation period of December 2008 through May 2009. Management cannot predict the outcome of the pending proceedings, including the treatment of the insurance proceeds, and whether any fuel clause revenues will have to be refunded as a result which could adversely affect future net income and cash flows.

Michigan Rate Matters

2008 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown) – Affecting I&M

In March 2009, I&M filed with the Michigan Public Service Commission (MPSC) its 2008 PSCR reconciliation. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Plant Unit 1 accidental outage policy, which began in mid-December 2008. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. In May 2009, the MPSC set a procedural schedule for testimony and hearings to be held in the fourth quarter of 2009. A final order is anticipated in the first quarter of 2010. Management is unable to predict the outcome of this proceeding and its possible adverse effect on future net income and cash flows.

Oklahoma Rate Matters

PSO Fuel and Purchased Power – Affecting PSO

2006 and Prior Fuel and Purchased Power

Proceedings addressing PSO's historic fuel costs from 2001 through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement. For further discussion and estimated effect on net income, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that concluded it was a FERC jurisdictional matter which allowed PSO to retain the $42 million it recovered from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending.

2007 Fuel and Purchased Power

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. In June 2009, the OCC staff recommended the OCC accept PSO's fuel adjustment clause and find that PSO's fuel procurement practices, policies and decisions were prudent. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

2008 Oklahoma Base Rate Filing – Affecting PSO

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million (later adjusted to $127 million) on an annual basis. At the time of the filing, PSO was recovering $16 million a year for costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO's net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues based on a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO's program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. The deferral was recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. During the second quarter of 2009, PSO accrued a regulatory liability of approximately $1 million related to a delay in installing gridSMART technologies as the OCC final order had included $2 million for this purpose.

PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment contained within the OCC final order to remove prepaid pension fund contributions from rate base. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several rate case issues. If the Attorney General or the intervenor's Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

Louisiana Rate Matters

2008 Formula Rate Filing – Affecting SWEPCo

In April 2008, SWEPCo filed its first formula rate filing under an approved three-year formula rate plan (FRP) which would increase its annual Louisiana retail rates by $11 million in August 2008 in order to earn an adjusted return on common equity of 10.565%. In August 2008, SWEPCo implemented the FRP rates, subject to refund. During the second quarter of 2009, SWEPCo recorded a provision for refund of approximately $1 million after reaching a settlement in principle with intervenors. SWEPCo is currently working with the parties to the settlement to prepare a written agreement to be filed with the LPSC for approval.

2009 Formula Rate Filing – Affecting SWEPCo

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional $4 million effective in August 2009 pursuant to the approved FRP. Since the rates as filed are in compliance with the FRP methodology previously approved by the LPSC, management expects that the LPSC will allow SWEPCo to implement the FRP rate increase as filed, subject to refund.

Stall Unit – Affecting SWEPCo

In May 2006, SWEPCo announced plans to build an intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit (Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $432 million, including $48 million of AFUDC, and is expected to be in service in mid-2010. In March 2007, the PUCT approved SWEPCo's request for a certificate of necessity for the facility based on a prior cost estimate.

The Louisiana Department of Environmental Quality issued an air permit for the Stall Unit in March 2008. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million including AFUDC and excluding related transmission costs. In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC staff filed testimony in March 2009 supporting the approval of the plant. The APSC staff also recommended that costs be capped at $445 million including AFUDC and excluding related transmission costs. In June 2009, the APSC approved the construction of the unit with a series of conditions consistent with those designated by the LPSC, including a requirement for an independent monitor and a $445 million cost cap.

As of June 30, 2009, SWEPCo has capitalized construction costs of $322 million, including AFUDC, and has contractual construction commitments of an additional $56 million with the total estimated cost to complete the unit at $432 million. If the total final cost of the Stall Unit exceeds the $445 million cost cap, it would have an adverse effect on net income and cash flows. If for any other reason SWEPCo cannot recover its capitalized costs, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Turk Plant – Affecting SWEPCo

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

Arkansas Rate Matters

Turk Plant – Affecting SWEPCo

In August 2006, SWEPCo announced plans to build the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. In 2007, the Oklahoma Municipal Power Authority (OMPA) acquired an approximate 7% ownership interest in the Turk Plant, paid SWEPCo $13.5 million for its share of the accrued construction costs and began paying its proportional share of ongoing costs. During the first quarter of 2009, the

Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) acquired ownership interests in the Turk Plant representing approximately 12% and 8%, respectively, and paid SWEPCo $104 million in the aggregate for their shares of accrued construction costs, and began paying their proportional shares of ongoing costs. The joint owners are billed monthly for their share of the on-going construction costs exclusive of AFUDC. Through June 30, 2009, the joint owners had paid SWEPCo $173 million for their share of the Turk construction expenditures. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's share estimated to cost $1.2 billion, excluding AFUDC. In addition, SWEPCo will own 100% of the related transmission facilities which are currently estimated to cost $131 million, excluding AFUDC.

In November 2007, the APSC granted approval for SWEPCo to build the Turk Plant in Arkansas at the existing site by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Certain intervenors appealed the APSC's decision to grant the CECPN to build the Turk Plant to the Arkansas Court of Appeals. In January 2009, the APSC granted additional CECPNs allowing SWEPCo to construct Turk-related transmission facilities. Intervenors also appealed these CECPN orders to the Arkansas Court of Appeals.

In June 2009, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN permitting construction of the Turk Plant to serve Arkansas retail customers. The decision was based upon the Arkansas Court of Appeals' interpretation of the statute that governs the certification process and its conclusion that the APSC did not fully comply with that process. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the generating plant and the proposed transmission facilities' construction and location should all have been considered by the APSC in a single docket instead of separate dockets. Both SWEPCo and the APSC petitioned the Arkansas Supreme Court to review the Arkansas Court of Appeals decision. SWEPCo's petition for review had the effect of staying the Arkansas Court of Appeals decision and, while the appeals are pending, SWEPCo is continuing construction of the Turk Plant. Management believes that the APSC properly interpreted and applied the Arkansas statutes governing the Turk Plant certification process and that SWEPCo's grounds for seeking review are strong.

If the decision of the Court of Appeals is not reversed by the Supreme Court of Arkansas, SWEPCo and the other joint owners of the Turk Plant will evaluate their options. Depending on the time taken by the Arkansas Supreme Court to consider the case and the reasoning of the Arkansas Supreme Court when it acts on SWEPCo's and the APSC's petitions, the construction schedule and/or the cost could be adversely affected. Should the appeal be unsuccessful, additional proceedings or alternative contractual, ownership and operational responsibilities could be required.

In March 2008, the LPSC approved the application to construct the Turk Plant. In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions as being unlawful. If the cost cap restrictions are upheld and construction or CO_2 emission costs exceed the restrictions, it could have an adverse effect on net income, cash flows and possibly financial condition. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in Federal District Court by certain Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals. In January 2009, SWEPCo filed a motion to dismiss the appeal, which was granted in March 2009.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. In December 2008, certain parties filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while the appeal of the Turk Plant's permit is heard. In June 2009, hearings on the air permit appeal were held at the APCEC. A decision is still pending and not expected until 2010. These same parties have filed a petition with the Federal EPA to review the air permit. If the air permit were to be remanded or ultimately revoked, construction of the Turk Plant could be suspended or cancelled. The Turk Plant cannot be placed into service without an air permit.

SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers an inadvertent impact on approximately 2.5 acres of wetlands at the Turk Plant construction site prior to the receipt of the permit. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas outside of the proposed Army Corps of Engineers permitted areas of the Turk Plant pending the Army Corps of Engineers review. SWEPCo has entered into a Consent Agreement and Final Order with the Federal EPA to resolve liability for the inadvertent impact and agreed to pay a civil penalty of approximately $29 thousand.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. To date, the report's effect is only advisory, but if legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's ability to complete construction on schedule in 2012 and on budget.

If the Turk Plant cannot be completed and placed in service, SWEPCo would seek approval to recover its prudently incurred capitalized construction costs including any cancellation fees and a return on unrecovered balances through rates in all of its jurisdictions. As of June 30, 2009, and excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $570 million of expenditures (including AFUDC and related transmission costs of $10 million) and has contractual construction commitments for an additional $582 million (including related transmission costs of $7 million). As of June 30, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $136 million (including related transmission cancellation fees of $1 million).

Management believes that SWEPCo's planning, certification and construction of the Turk Plant to date have been in material compliance with all applicable laws and regulations, except for the inadvertent wetlands intrusion discussed above. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if for any reason SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would adversely impact net income, cash flows and possibly financial condition unless the resultant losses can be fully recovered, with a return on unrecovered balances, through rates in all of its jurisdictions.

Arkansas Base Rate Filing – Affecting SWEPCo

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to recover financing costs related to the construction of the Stall Unit and Turk Plant. In June 2009, the APSC staff recommended a $15.5 million increase based on a return on equity of 10.25% and did not recommend any riders based upon the Arkansas State Court of Appeals' decision to reverse the APSC's grant of a Certificate of Environmental Compatibility and Public Need for the Turk Plant. See "Turk Plant" section above. In June 2009, the Arkansas Attorney General recommended a $12.9 million increase based on a return on equity of 10% and recommended part of the requested rider for the Stall Unit only. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

In January 2009, an ice storm struck in northern Arkansas affecting SWEPCo's customers. SWEPCo incurred approximately $4 million in incremental operation and maintenance expenses above the estimated amount of storm restoration costs included in existing base rates. In May 2009, SWEPCo filed an application with the APSC seeking authority to defer the $4 million of expensed incremental operation and maintenance costs and to address the recovery of these deferred expenses in the pending base rate case. Staff testimony in this case supports SWEPCo's request, subject to an audit of the incurred costs. In July 2009, the APSC issued an order approving the deferral request subject to investigation, analysis and audit of the costs. Management is unable to predict the outcome of this application.

Stall Unit – Affecting SWEPCo

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

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary 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. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. 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

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 should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's 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. AEP and SECA ratepayers are engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. APCo's, CSPCo's, I&M's and OPCo's portions of the provision are as follows:

Company	2007	2006
	(in millions)	
APCo	$ 1.7	$ 12.4
CSPCo	0.9	6.9
I&M	1.0	7.3
OPCo	1.3	9.4

In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. As of June 30, 2009, there were no in-process settlements. APCo's, CSPCo's, I&M's and OPCo's reserve balance at June 30, 2009 was:

Company	June 30, 2009 (in millions)
APCo	$ 10.7
CSPCo	5.9
I&M	6.3
OPCo	8.2

Management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims cannot be settled and are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this review will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. The AEP East companies sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. In January and March 2009, the AEP East companies received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, the AEP East companies are now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of the AEP East companies' transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings to reflect the resultant additional transmission cost reductions. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing – Affecting APCo, CSPCo, I&M and OPCo

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP’s proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ, and delayed the requested October 2008 effective date for five months. The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies’ transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected. Retail rates for CSPCo and OPCo would be increased on an annual basis through the TCRR by approximately $10 million and $13 million, respectively. The TCRR includes a true-up mechanism so CSPCo’s and OPCo’s net income will not be adversely affected by a FERC-ordered transmission rate increase. In October 2008, AEP filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing.

In May 2009, the first annual update of the formula rate was filed with the FERC which reflected increased transmission service revenue requirements of approximately $32 million on an annualized basis, effective for service as of July 1, 2009 to be billed in August 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM. Retail rates for CSPCo and OPCo would be increased through the TCRR totaling approximately $5 million and $7 million, respectively. Beginning in December 2009, APCo's Virginia transmission rate adjustment clause is expected to become effective and thus recover approximately $2 million of this increase. Retail rates for other AEP East jurisdictions are not directly affected.

Under the formula, the second annual update will be filed effective July 1, 2010 and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

SPP Transmission Formula Rate Filing – Affecting PSO and SWEPCo

In June 2007, AEPSC filed revised tariffs to establish an up-to-date revenue requirement for SPP transmission services over the facilities owned by PSO and SWEPCo and to implement a transmission cost of service formula rate. PSO and SWEPCo requested an effective date of September 1, 2007 for the revised tariff. If approved as filed, the revised tariff will increase annual network transmission service revenues from nonaffiliated municipal and rural cooperative utilities in the AEP pricing zone of SPP by approximately $10 million.

In August 2007, the FERC issued an order conditionally accepting PSO’s and SWEPCo’s proposed formula rate, subject to a compliance filing, suspended the effective date until February 1, 2008 and established a hearing schedule and settlement proceedings. New rates, subject to refund, were implemented in February 2008. Multiple intervenors have protested or requested rehearing of the August 2007 order. In October 2007, PSO and SWEPCo filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. Under the formula, rates will be updated effective July 1, 2009, and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. In February 2009, a settlement agreement was reached and was filed with the FERC. During the first six months of 2009, a provision for refund was recorded by PSO and SWEPCo based upon the pending settlement. In June 2009, the FERC approved the settlement agreement and refunds were made to customers.

Allocation of Off-system Sales Margins – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund reflecting the sharing. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction amount to be included in the March 2009 fuel cost report submitted to the PUCT. PSO began refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. SWEPCo is working with the APSC and the LPSC to determine the effect the FERC order will have on retail rates. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding related future state regulatory proceedings is adequate.

Modification of the Transmission Agreement (TA) – Affecting APCo, CSPCo, I&M and OPCo

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA entered into in 1984, as amended, that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations operated at 345kV and above. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, WPCo and KGPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse the majority of PJM transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. Management is unable to predict the outcome of this proceeding and the effect, if any, it will have on future net income and cash flows due to timing of implementation by various state regulators.

Transmission Agreement (TA) – Affecting APCo, CSPCo, I&M and OPCo

Certain transmission equipment placed in service in 1998 was inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was the Inez station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was $7 million annually. Management does not believe that it is probable that a material retroactive rate adjustment will result from the omission. However, if a retroactive adjustment is required, APCo, CSPCo, I&M and OPCo could experience adverse effects on future net income, cash flows and financial condition.

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 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

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 – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits and debt service reserves. These LOCs were issued in the ordinary course of business under the two $1.5 billion credit facilities.

The Registrant Subsidiaries and certain other companies in the AEP System have a $627 million 3-year credit agreement. As of June 30, 2009, $372 million of letters of credit were issued by Registrant Subsidiaries under the $627 million 3-year credit agreement to support variable rate Pollution Control Bonds. The Registrant Subsidiaries and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

At June 30, 2009, the maximum future payments of the LOCs were as follows:

Company	Amount (in thousands)	Maturity	Borrower Sublimit
$1.5 billion LOC:			
I&M	$ 300	March 2010	N/A
SWEPCo	4,448	December 2009	N/A
$627 million LOC:			
APCo	$ 126,716	June 2010	$ 300,000
I&M	77,886	May 2010	230,000
OPCo	166,899	June 2010	400,000

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), an entity consolidated under FIN 46R. 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. A new study is in process to include new, expanded areas of the mine. As of June 30, 2009, SWEPCo has collected approximately $40 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $16 million is recorded in Asset Retirement Obligations and $22 million is recorded in Deferred Credits and Other Noncurrent Liabilities on SWEPCo's Condensed Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

Contracts

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, 2009, Registrant Subsidiaries entered into sale agreements which included 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 Lease Agreements

Certain Registrant Subsidiaries lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2010 and 2011, the Registrant Subsidiaries will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into additional replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2010 and 2011.

For equipment under the GE master lease agreements that expire prior to 2011, 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, the Registrant Subsidiaries 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. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. At June 30, 2009, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss (in thousands)
APCo	$ 913
CSPCo	379
I&M	618
OPCo	799
PSO	1,089
SWEPCo	738

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of June 30, 2009.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five-year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair market value would produce a sufficient sales price to avoid any loss.

The Registrant Subsidiaries have other railcar lease arrangements that do not utilize this type of financing structure.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting CSPCo

The Federal EPA, certain special interest groups and a number of states alleged that a unit jointly owned by CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. at the Beckjord Station was modified in violation of the NSR requirements of the CAA.

The Beckjord case had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. Following a second liability trial, the jury again found no liability at the jointly-owned Beckjord unit. Beckjord is operated by Duke Energy Ohio, Inc.

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. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs. The consent decree was entered as a final order in June 2008.

In February 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that a permit alteration issued by Texas Commission on Environmental Quality was improper. SWEPCo met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. Management is unable to predict the timing of any future action by the Federal EPA or the effect of such actions on net income, 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 dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 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 U.S. Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims – Affecting AEP East Companies and AEP West Companies

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting I&M

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. Costs are currently being incurred to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms and started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $4 million of expense during 2008. Based upon updated information, I&M recorded additional expense of $3 million in March 2009. As the remediation work is completed, I&M's cost may continue to increase. I&M cannot predict the amount of additional cost, if any.

Defective Environmental Equipment – Affecting CSPCo and OPCo

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on units utilizing the JBR technology. The retrofits on two units are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. Management intends to pursue contractual and other legal remedies if these issues with Black & Veatch are not resolved. If the AEP System is unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition.

Cook Plant Unit 1 Fire and Shutdown – Affecting I&M

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and facilitate repairs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. I&M is repairing Unit 1 to resume operations as early as October 2009 at reduced power. Should post-repair operations prove unsuccessful, the replacement of parts will extend the outage into 2011.

The refueling outage scheduled for the fall of 2009 for Unit 1 was rescheduled to the spring of 2010. Management anticipates that the loss of capacity from Unit 1 will not affect I&M's ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.

I&M maintains property insurance through NEIL with a $1 million deductible. As of June 30, 2009, I&M recorded $54 million in Prepayments and Other Current Assets on its Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. I&M received partial reimbursement from NEIL for the cost incurred to date to repair the property damage. I&M also maintains a separate accidental outage policy with

NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy in December 2008. In 2009, I&M recorded $99 million in revenues, including $9 million that were deferred at December 31, 2008, related to the accidental outage policy. In 2009, I&M applied $40 million of the accidental outage insurance proceeds to reduce customer bills. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

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 defend its position that PSO paid BNSF all amounts owed.

Rail Transportation Litigation – Affecting PSO

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied AEP's motion to dismiss the case. Management intends to vigorously defend against these allegations. Management believes a provision recorded in 2008 should be sufficient.

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. In 2003, the FERC rejected the complaint. In 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. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. 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. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.

5. ACQUISITION

2009

Oxbow Mine Lignite – Affecting SWEPCo

In April 2009, SWEPCo agreed to purchase 50% of the Oxbow Mine lignite reserves for $13 million and Dolet Hills Lignite Company, LLC agreed to purchase 100% of all associated mining equipment and assets for $16 million from the North American Coal Corporation and its affiliates, Red River Mining Company and Oxbow Property Company, LLC. Cleco Power LLC (Cleco) will acquire the remaining 50% interest in the lignite reserves for $13 million. SWEPCo expects to complete the transaction in the fourth quarter of 2009. Consummation of the transaction is subject to regulatory approval by the LPSC and the APSC and the transfer of other regulatory instruments. If approved, DHLC will acquire and own the Oxbow Mine mining equipment and related assets and it will operate the Oxbow Mine. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and Cleco's jointly-owned Dolet Hills Generating Station.

2008

None

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.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 11	$ 11
Interest Cost	64	62	28	28
Expected Return on Plan Assets	(81)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	6	7
Amortization of Net Actuarial Loss	15	10	10	2
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 52	$ 50	$ 21	$ 21
Interest Cost	127	125	55	56
Expected Return on Plan Assets	(161)	(168)	(40)	(56)
Amortization of Transition Obligation	-	-	13	14
Amortization of Net Actuarial Loss	30	19	21	5
Net Periodic Benefit Cost	$ 48	$ 26	$ 70	$ 40

The following tables provide the Registrant Subsidiaries' net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2009	2008	2009	2008
Company	(in thousands)			
APCo	$ 2,615	$ 834	$ 6,057	$ 3,700
CSPCo	688	(349)	2,639	1,499
I&M	3,485	1,820	4,358	2,423
OPCo	2,067	320	5,140	2,817
PSO	770	508	2,284	1,387
SWEPCo	1,207	936	2,364	1,376

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Company	(in thousands)			
APCo	$ 5,230	$ 1,669	$ 12,115	$ 7,399
CSPCo	1,376	(698)	5,277	2,997
I&M	6,970	3,641	8,716	4,846
OPCo	4,134	639	10,279	5,633
PSO	1,540	1,016	4,567	2,774
SWEPCo	2,415	1,871	4,727	2,752

7. BUSINESS SEGMENTS

The Registrant Subsidiaries have one reportable segment. The one reportable segment is an electricity generation, transmission and distribution business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed as one segment because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. DERIVATIVES AND HEDGING

Objectives for Utilization of Derivative Instruments

The Registrant Subsidiaries are exposed to certain market risks as major power producers and marketers of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and to a lesser extent foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrant Subsidiaries due to changes in the underlying market prices or rates. These risks are managed using derivative instruments.

Strategies for Utilization of Derivative Instruments to Achieve Objectives

The Registrant Subsidiaries' strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal SFAS 133 hedging strategies. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

AEPSC, on behalf of the Registrant Subsidiaries, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with long-term commodity derivative positions. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. From time to time, AEPSC, on behalf of the Registrant Subsidiaries, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of June 30, 2009:

Notional Volume of Derivative Instruments
June 30, 2009
(in thousands)

Primary Risk Exposure	Unit of Measure	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
Commodity:							
Power	MWHs	185,883	98,584	95,407	122,120	414	487
Coal	Tons	11,009	5,481	6,293	21,540	3,870	5,408
Natural Gas	MMBtus	32,784	17,387	16,827	21,538	3,851	4,538
Heating Oil and Gasoline	Gallons	1,490	612	708	1,073	849	799
Interest Rate	USD	$ 41,428	$ 21,922	$ 21,353	$ 29,141	$ 2,352	$ 3,083
Interest Rate and Foreign Currency	USD	$ -	$ -	$ -	$ 400,000	$ -	$ 3,932

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative transactions in order to manage an existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. This strategy is not actively employed by any of the Registrant Subsidiaries in 2009. During 2008, APCo had designated interest rate derivatives as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk. During 2009 and 2008, APCo, CSPCo, I&M and OPCo designated cash flow hedging relationships using these commodities.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial gasoline and heating oil derivative contracts in order to mitigate price risk of future fuel purchases. The Registrant Subsidiaries do not hedge all fuel price risk. During 2009, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for any of the Registrant Subsidiaries during 2008. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. The Registrant Subsidiaries do not hedge all interest rate exposure. During 2009, OPCo designated interest rate derivatives as cash flow hedges. During 2008, APCo and OPCo designated interest rate derivatives as cash flow hedges.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrant Subsidiaries do not hedge all foreign currency exposure. During 2009, SWEPCo designated foreign currency derivatives as cash flow hedges. During 2008, APCo, OPCo and SWEPCo designated foreign currency derivatives as cash flow hedges.

Accounting for Derivative Instruments and the Impact on the Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrant Subsidiaries also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to FSP FIN 39-1, the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2009 and December 31, 2008 balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	June 30, 2009		December 31, 2008	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)			
APCo	$ 11,055	$ 33,080	$ 2,189	$ 5,621
CSPCo	5,863	17,542	1,229	3,156
I&M	5,674	16,982	1,189	3,054
OPCo	7,263	21,800	1,522	3,909
PSO	-	136	-	105
SWEPCo	-	171	-	124

The following table represents the gross fair value impact of the Registrant Subsidiaries' derivative activity on the Condensed Balance Sheets as of June 30, 2009:

Fair Value of Derivative Instruments
June 30, 2009

APCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 610,801	$ 6,901	$ -	$ (537,139)	$ 80,563
Long-term Risk Management Assets	215,917	1,821	-	(160,345)	57,393
Total Assets	826,718	8,722	-	(697,484)	137,956
Current Risk Management Liabilities	581,898	4,475	-	(552,194)	34,179
Long-term Risk Management Liabilities	195,182	1,731	-	(174,279)	22,634
Total Liabilities	777,080	6,206	-	(726,473)	56,813
Total MTM Derivative Contract Net Assets (Liabilities)	$ 49,638	$ 2,516	$ -	$ 28,989	$ 81,143

CSPCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 321,847	$ 3,629	$ -	$ (283,078)	$ 42,398
Long-term Risk Management Assets	113,877	953	-	(84,449)	30,381
Total Assets	435,724	4,582	-	(367,527)	72,779
Current Risk Management Liabilities	306,637	2,374	-	(291,062)	17,949
Long-term Risk Management Liabilities	102,905	917	-	(91,838)	11,984
Total Liabilities	409,542	3,291	-	(382,900)	29,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 26,182	$ 1,291	$ -	$ 15,373	$ 42,846

I&M

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 317,092	$ 3,533	$ -	$ (278,914)	$ 41,711
Long-term Risk Management Assets	111,961	930	-	(83,356)	29,535
Total Assets	429,053	4,463	-	(362,270)	71,246
Current Risk Management Liabilities	302,042	2,296	-	(286,640)	17,698
Long-term Risk Management Liabilities	101,275	889	-	(90,511)	11,653
Total Liabilities	403,317	3,185	-	(377,151)	29,351
Total MTM Derivative Contract Net Assets (Liabilities)	$ 25,736	$ 1,278	$ -	$ 14,881	$ 41,895

OPCo

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 484,204	$ 4,552	$ 30,356	$ (423,208)	$ 95,904
Long-term Risk Management Assets	167,044	1,201	-	(128,076)	40,169
Total Assets	651,248	5,753	30,356	(551,284)	136,073
Current Risk Management Liabilities	463,042	2,939	-	(433,097)	32,884
Long-term Risk Management Liabilities	154,683	1,137	-	(137,298)	18,522
Total Liabilities	617,725	4,076	-	(570,395)	51,406
Total MTM Derivative Contract Net Assets (Liabilities)	$ 33,523	$ 1,677	$ 30,356	$ 19,111	$ 84,667

PSO

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 27,968	$ 164	$ -	$ (22,824)	$ 5,308
Long-term Risk Management Assets	5,009	71	-	(4,609)	471
Total Assets	32,977	235	-	(27,433)	5,779
Current Risk Management Liabilities	27,508	54	-	(22,882)	4,680
Long-term Risk Management Liabilities	4,946	-	-	(4,592)	354
Total Liabilities	32,454	54	-	(27,474)	5,034
Total MTM Derivative Contract Net Assets (Liabilities)	$ 523	$ 181	$ -	$ 41	$ 745

SWEPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 45,630	$ 156	$ -	$ (38,082)	$ 7,704
Long-term Risk Management Assets	9,860	47	5	(9,105)	807
Total Assets	55,490	203	5	(47,187)	8,511
Current Risk Management Liabilities	43,716	-	153	(38,151)	5,718
Long-term Risk Management Liabilities	9,520	-	-	(9,095)	425
Total Liabilities	53,236	-	153	(47,246)	6,143
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,254	$ 203	$ (148)	$ 59	$ 2,368

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Balance Sheets on a net basis in accordance with FIN 39 “Offsetting of Amounts Related to Certain Contracts.”

(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The tables below presents the Registrant Subsidiaries MTM activity of derivative risk management contracts for the three and six months ended June 30, 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Three Months Ended June 30, 2009

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)					
Electric Generation, Transmission and Distribution Revenues	$ 1,184	$ 9,261	$ 6,028	$ 10,804	$ (407)	$ (305)
Sales to AEP Affiliates	(306)	(393)	(447)	1,721	837	806
Regulatory Assets	-	-	-	-	-	(62)
Regulatory Liabilities	18,827	1,540	4,751	1,771	(1,339)	(324)
Total Gain (Loss) on Risk Management Contracts	$ 19,705	$ 10,408	$ 10,332	$ 14,296	$ (909)	$ 115

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Six Months Ended June 30, 2009

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)					
Electric Generation, Transmission and Distribution Revenues	$ 10,971	$ 20,006	$ 24,206	$ 24,298	$ 848	$ 1,218
Sales to AEP Affiliates	(7,326)	(4,469)	(4,418)	(1,493)	(625)	(975)
Regulatory Assets	(755)	-	-	-	-	(103)
Regulatory Liabilities	50,358	11,076	6,368	13,036	(882)	249
Total Gain (Loss) on Risk Management Contracts	$ 53,248	$ 26,613	$ 26,156	$ 35,841	$ (659)	$ 389

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Condensed Statements of Income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Condensed Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Condensed Statements of Income depending on the relevant facts and circumstances. However, unrealized and realized gains and losses in regulated jurisdictions (APCo, I&M, PSO, the non-Texas portion of SWEPCo generation and beginning April 2009 the Texas portion of SWEPCo generation) for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with SFAS 71. SWEPCo returned to cost based regulation and re-applied SFAS 71 regulatory accounting for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009.

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the Registrant Subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk in Net Income during the period of change.

The Registrant Subsidiaries record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on the Condensed Statements of Income. During the three and six months ended June 30, 2009, the Registrant Subsidiaries did not employ any fair value hedging strategies. During the three and six months ended June 30, 2008, APCo designated interest rate derivatives as fair value hedges and did not recognize any hedge ineffectiveness related to these derivative transactions.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale in the Condensed Statements of Income, depending on the specific nature of the risk being hedged. The Registrant Subsidiaries do not hedge all variable price risk exposure related to commodities. During the three and six months ended June 30, 2009 and 2008, APCo, CSPCo, I&M and OPCo recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, the Registrant Subsidiaries executed financial heating oil and gasoline derivative contracts to hedge the price risk of diesel fuel and gasoline purchases. The Registrant Subsidiaries reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation and Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Condensed Statements of Income. The Registrant Subsidiaries do not hedge all fuel price exposure. During the three and six months ended June 30, 2009, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo recognized no hedge ineffectiveness related to this hedge strategy.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2009, OPCo recognized a gain of $7.4 million in Interest Expense related to hedge ineffective on interest rate derivatives designated as cash flow hedges. During the three and six months ended June 30, 2008, APCo and OPCo recognized immaterial amounts in Interest Expense related to hedge ineffectiveness.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Depreciation and Amortization expense in the Condensed Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. The Registrant Subsidiaries do not hedge all foreign currency exposure. During the three and six months ended June 30, 2009 and 2008, APCo, OPCo and SWEPCo recognized no hedge ineffectiveness related to this hedge strategy.

The following tables provides details on designated, effective cash flow hedges included in AOCI on the Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2009. All amounts in the following tables are presented net of related income taxes.

Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2009

	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Commodity Contracts						
Beginning Balance in AOCI as of April 1, 2009	$ 4,066	$ 2,162	$ 2,091	$ 2,669	$ (24)	$ (21)
Changes in Fair Value Recognized in AOCI	(207)	(143)	(119)	(115)	155	166
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Electric Generation, Transmission and Distribution Revenues	(458)	(1,158)	(885)	(1,434)	-	-
Fuel and Other Consumables Used for Electric Generation	(6)	(4)	(4)	(5)	(3)	(3)
Purchased Electricity for Resale	132	334	255	413	-	-
Property, Plant and Equipment	(3)	(2)	(1)	(2)	(1)	(1)
Regulatory Assets	497	-	68	-	-	-
Regulatory Liabilities	(1,725)	-	(235)	-	-	-
Ending Balance in AOCI as of June 30, 2009	$ 2,296	$ 1,189	$ 1,170	$ 1,526	$ 127	$ 141

	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Interest Rate and Foreign Currency Contracts						
Beginning Balance in AOCI as of April 1, 2009	$ (7,702)	$ -	$ (10,271)	$ 2,039	$ (658)	$ (5,808)
Changes in Fair Value Recognized in AOCI	-	-	-	14,690	-	104
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Depreciation and Amortization Expense	-	-	-	1	-	-
Interest Expense	417	-	254	(68)	45	207
Ending Balance in AOCI as of June 30, 2009	$ (7,285)	$ -	$ (10,017)	$ 16,662	$ (613)	$ (5,497)

TOTAL Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of April 1, 2009	$ (3,636)	$ 2,162	$ (8,180)	$ 4,708	$ (682)	$ (5,829)
Changes in Fair Value Recognized in AOCI	(207)	(143)	(119)	14,575	155	270
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Electric Generation, Transmission and Distribution Revenues	(458)	(1,158)	(885)	(1,434)	-	-
Fuel and Other Consumables Used for Electric Generation	(6)	(4)	(4)	(5)	(3)	(3)
Purchased Electricity for Resale	132	334	255	413	-	-
Depreciation and Amortization Expense	-	-	-	1	-	-
Interest Expense	417	-	254	(68)	45	207
Property, Plant and Equipment	(3)	(2)	(1)	(2)	(1)	(1)
Regulatory Assets	497	-	68	-	-	-
Regulatory Liabilities	(1,725)	-	(235)	-	-	-
Ending Balance in AOCI as of June 30, 2009	$ (4,989)	$ 1,189	$ (8,847)	$ 18,188	$ (486)	$ (5,356)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2009

Commodity Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of January 1, 2009	$ 2,726	$ 1,531	$ 1,482	$ 1,898	$ -	$ -
Changes in Fair Value Recognized in AOCI	173	(25)	(6)	21	131	145
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Electric Generation, Transmission and Distribution Revenues	(709)	(1,771)	(1,389)	(2,193)	-	-
Fuel and Other Consumables Used for Electric Generation	(6)	(4)	(4)	(5)	(3)	(3)
Purchased Electricity for Resale	594	1,460	1,181	1,807	-	-
Property, Plant and Equipment	(3)	(2)	(1)	(2)	(1)	(1)
Regulatory Assets	2,136	-	231	-	-	-
Regulatory Liabilities	(2,615)	-	(324)	-	-	-
Ending Balance in AOCI as of June 30, 2009	$ 2,296	$ 1,189	$ 1,170	$ 1,526	$ 127	$ 141

Interest Rate and Foreign Currency Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of January 1, 2009	$ (8,118)	$ -	$ (10,521)	$ 1,752	$ (704)	$ (5,924)
Changes in Fair Value Recognized in AOCI	-	-	-	14,953	-	13
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Depreciation and Amortization Expense	-	-	(2)	2	-	-
Interest Expense	833	-	506	(45)	91	414
Ending Balance in AOCI as of June 30, 2009	$ (7,285)	$ -	$ (10,017)	$ 16,662	$ (613)	$ (5,497)

TOTAL Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Beginning Balance in AOCI as of January 1, 2009	$ (5,392)	$ 1,531	$ (9,039)	$ 3,650	$ (704)	$ (5,924)
Changes in Fair Value Recognized in AOCI	173	(25)	(6)	14,974	131	158
Amount of (Gain) or Loss Reclassified from AOCI to Income Statements/within Balance Sheets:						
Electric Generation, Transmission and Distribution Revenues	(709)	(1,771)	(1,389)	(2,193)	-	-
Fuel and Other Consumables Used for Electric Generation	(6)	(4)	(4)	(5)	(3)	(3)
Purchased Electricity for Resale	594	1,460	1,181	1,807	-	-
Depreciation and Amortization Expense	-	-	(2)	2	-	-
Interest Expense	833	-	506	(45)	91	414
Property, Plant and Equipment	(3)	(2)	(1)	(2)	(1)	(1)
Regulatory Assets	2,136	-	231	-	-	-
Regulatory Liabilities	(2,615)	-	(324)	-	-	-
Ending Balance in AOCI as of June 30, 2009	$ (4,989)	$ 1,189	$ (8,847)	$ 18,188	$ (486)	$ (5,356)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets at June 30, 2009 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Condensed Balance Sheets June 30, 2009

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
	(in thousands)					
APCo	$ 4,862	$ -	$ (2,346)	$ -	$ 2,296	$ (7,285)
CSPCo	2,536	-	(1,245)	-	1,189	-
I&M	2,482	-	(1,204)	-	1,170	(10,017)
OPCo	3,219	30,356	(1,542)	-	1,526	16,662
PSO	235	-	(54)	-	127	(613)
SWEPCo	204	4	-	(153)	141	(5,497)

	Expected to be Reclassified to Net Income During the Next Twelve Months		
Company	Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$ 2,238	$ (1,617)	20
CSPCo	1,166	-	20
I&M	1,142	(1,007)	20
OPCo	1,484	953	20
PSO	81	(169)	18
SWEPCo	111	(829)	41

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the Condensed Balance Sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

The Registrant Subsidiaries limit credit risk in their wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. The Registrant Subsidiaries use Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

The Registrant Subsidiaries use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), the Registrant Subsidiaries are obligated to post an amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, the risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. The following table represents the Registrant Subsidiaries' aggregate fair value of such contracts, the amount of collateral the Registrant Subsidiaries would have been required to post if the credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of June 30, 2009.

Company	Aggregate Fair Value Contracts	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 15,931	$ 15,931	$ 14,784
CSPCo	8,449	8,449	7,841
I&M	8,177	8,177	7,588
OPCo	10,466	10,466	9,713
PSO	5,888	5,888	5,692
SWEPCo	6,940	6,940	6,709

As of June 30, 2009, the Registrant Subsidiaries were not required to post any collateral.

9. FAIR VALUE MEASUREMENTS

With the adoption of three new accounting standards, the Registrant Subsidiaries are required to provide certain fair value disclosures which were previously only required in the annual report. The new standards did not change the method to calculate the amounts reported on the balance sheets.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries at June 30, 2009 and December 31, 2008 are summarized in the following table:

	June 30, 2009		December 31, 2008	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
APCo	$ 3,371,788	$ 3,318,561	$ 3,174,512	$ 2,858,278
CSPCo	1,443,799	1,430,222	1,443,594	1,410,609
I&M	1,975,138	1,949,360	1,377,914	1,308,712
OPCo	2,962,202	2,971,092	3,039,376	2,953,131
PSO	868,679	860,034	884,859	823,150
SWEPCo	1,476,151	1,467,597	1,478,149	1,358,122

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether the investor has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment, among other things, is based on whether the investor has the ability and intent to hold the investment to recover its value. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions' liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at June 30, 2009 and December 31, 2008:

	June 30, 2009			December 31, 2008		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash	$ 16	$ -	$ -	$ 18	$ -	$ -
Debt Securities	767	28	(3)	773	52	(3)
Equity Securities	485	145	(135)	469	89	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,268	$ 173	$ (138)	$ 1,260	$ 141	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2009:

	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
	(in millions)			
Three Months Ended	$ 253	$ 264	$ 6	$ (1)
Six Months Ended	411	442	9	(1)

The amortized cost of debt securities was $739 million and $721 million as of June 30, 2009 and December 31, 2008, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at June 30, 2009 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 40
1 year – 5 years	214
5 years – 10 years	242
After 10 years	271
Total	$ 767

Fair Value Measurements of Financial Assets and Liabilities

As described in the 2008 Annual Report, SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Derivatives, Hedging and Fair Value Measurements note within the 2008 Annual Report should be read in conjunction with this report.

Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

The following tables set forth by level within the fair value hierarchy the financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009 and December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 421	$ -	$ -	$ 51	$ 472
Risk Management Assets					
Risk Management Contracts (a)	12,014	789,285	22,112	(701,248)	122,163
Cash Flow and Fair Value Hedges (a)	-	8,652	-	(3,790)	4,862
Dedesignated Risk Management Contracts (b)	-	-	-	10,931	10,931
Total Risk Management Assets	12,014	797,937	22,112	(694,107)	137,956
Total Assets	$ 12,435	$ 797,937	$ 22,112	$ (694,056)	$ 138,428
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 13,094	$ 752,466	$ 8,212	$ (723,273)	$ 50,499
Cash Flow and Fair Value Hedges (a)	-	6,136	-	(3,790)	2,346
DETM Assignment (c)	-	-	-	3,968	3,968
Total Risk Management Liabilities	$ 13,094	$ 758,602	$ 8,212	$ (723,095)	$ 56,813

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 656	$ -	$ -	$ 52	$ 708
Risk Management Assets					
Risk Management Contracts (a)	16,105	667,748	11,981	(597,676)	98,158
Cash Flow and Fair Value Hedges (a)	-	6,634	-	(1,413)	5,221
Dedesignated Risk Management Contracts (b)	-	-	-	12,856	12,856
Total Risk Management Assets	16,105	674,382	11,981	(586,233)	116,235
Total Assets	$ 16,761	$ 674,382	$ 11,981	$ (586,181)	$ 116,943
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 18,808	$ 628,974	$ 3,972	$ (601,108)	$ 50,646
Cash Flow and Fair Value Hedges (a)	-	2,545	-	(1,413)	1,132
DETM Assignment (c)	-	-	-	5,230	5,230
Total Risk Management Liabilities	$ 18,808	$ 631,519	$ 3,972	$ (597,291)	$ 57,008

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 20,054	$ -	$ -	$ 1,171	$ 21,225
Risk Management Assets					
Risk Management Contracts (a)	6,371	415,979	11,726	(369,631)	64,445
Cash Flow and Fair Value Hedges (a)	-	4,545	-	(2,009)	2,536
Dedesignated Risk Management Contracts (b)	-	-	-	5,798	5,798
Total Risk Management Assets	6,371	420,524	11,726	(365,842)	72,779
Total Assets	$ 26,425	$ 420,524	$ 11,726	$ (364,671)	$ 94,004
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 6,944	$ 396,596	$ 4,354	$ (381,310)	$ 26,584
Cash Flow and Fair Value Hedges (a)	-	3,254	-	(2,009)	1,245
DETM Assignment (c)	-	-	-	2,104	2,104
Total Risk Management Liabilities	$ 6,944	$ 399,850	$ 4,354	$ (381,215)	$ 29,933

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 31,129	$ -	$ -	$ 1,171	$ 32,300
Risk Management Assets					
Risk Management Contracts (a)	9,042	366,557	6,724	(328,027)	54,296
Cash Flow and Fair Value Hedges (a)	-	3,725	-	(794)	2,931
Dedesignated Risk Management Contracts (b)	-	-	-	7,218	7,218
Total Risk Management Assets	9,042	370,282	6,724	(321,603)	64,445
Total Assets	$ 40,171	$ 370,282	$ 6,724	$ (320,432)	$ 96,745
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 10,559	$ 344,860	$ 2,227	$ (329,954)	$ 27,692
Cash Flow and Fair Value Hedges (a)	-	1,429	-	(794)	635
DETM Assignment (c)	-	-	-	2,937	2,937
Total Risk Management Liabilities	$ 10,559	$ 346,289	$ 2,227	$ (327,811)	$ 31,264

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 6,166	$ 409,813	$ 11,352	$ (364,177)	$ 63,154
Cash Flow and Fair Value Hedges (a)	-	4,427	-	(1,945)	2,482
Dedesignated Risk Management Contracts (b)	-	-	-	5,610	5,610
Total Risk Management Assets	6,166	414,240	11,352	(360,512)	71,246
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	5,280	-	10,792	16,072
Debt Securities (f)	-	766,773	-	-	766,773
Equity Securities (g)	485,597	-	-	-	485,597
Total Spent Nuclear Fuel and Decommissioning Trusts	485,597	772,053	-	10,792	1,268,442
Total Assets	$ 491,763	$ 1,186,293	$ 11,352	$ (349,720)	$ 1,339,688
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 6,720	$ 390,658	$ 4,217	$ (375,485)	$ 26,110
Cash Flow and Fair Value Hedges (a)	-	3,149	-	(1,945)	1,204
DETM Assignment (c)	-	-	-	2,037	2,037
Total Risk Management Liabilities	$ 6,720	$ 393,807	$ 4,217	$ (375,393)	$ 29,351

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

I&M

Assets:	**Level 1**	**Level 2**	**Level 3**	**Other**	**Total**
			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 8,750	$ 357,405	$ 6,508	$ (319,857)	$ 52,806
Cash Flow and Fair Value Hedges (a)	-	3,605	-	(768)	2,837
Dedesignated Risk Management Contracts (b)	-	-	-	6,985	6,985
Total Risk Management Assets	8,750	361,010	6,508	(313,640)	62,628
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	7,818	-	11,845	19,663
Debt Securities (f)	-	771,216	-	-	771,216
Equity Securities (g)	468,654	-	-	-	468,654
Total Spent Nuclear Fuel and Decommissioning Trusts	468,654	779,034	-	11,845	1,259,533
Total Assets	$ 477,404	$ 1,140,044	$ 6,508	$ (301,795)	$ 1,322,161
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 10,219	$ 336,280	$ 2,156	$ (321,722)	$ 26,933
Cash Flow and Fair Value Hedges (a)	-	1,383	-	(768)	615
DETM Assignment (c)	-	-	-	2,842	2,842
Total Risk Management Liabilities	$ 10,219	$ 337,663	$ 2,156	$ (319,648)	$ 30,390

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

OPCo

Assets:	**Level 1**	**Level 2**	**Level 3**	**Other**	**Total**
			(in thousands)		
Other Cash Deposits (d)	$ 1,074	$ -	$ -	$ 1,674	$ 2,748
Risk Management Assets					
Risk Management Contracts (a)	7,892	623,403	14,845	(550,824)	95,316
Cash Flow and Fair Value Hedges (a)	-	36,064	-	(2,489)	33,575
Dedesignated Risk Management Contracts (b)	-	-	-	7,182	7,182
Total Risk Management Assets	7,892	659,467	14,845	(546,131)	136,073
Total Assets	$ 8,966	$ 659,467	$ 14,845	$ (544,457)	$ 138,821
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 8,602	$ 598,581	$ 5,435	$ (565,361)	$ 47,257
Cash Flow and Fair Value Hedges (a)	-	4,031	-	(2,489)	1,542
DETM Assignment (c)	-	-	-	2,607	2,607
Total Risk Management Liabilities	$ 8,602	$ 602,612	$ 5,435	$ (565,243)	$ 51,406

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 4,197	$ -	$ -	$ 2,431	$ 6,628
Risk Management Assets					
Risk Management Contracts (a)	11,200	575,415	8,364	(515,162)	79,817
Cash Flow and Fair Value Hedges (a)	-	4,614	-	(983)	3,631
Dedesignated Risk Management Contracts (b)	-	-	-	8,941	8,941
Total Risk Management Assets	11,200	580,029	8,364	(507,204)	92,389
Total Assets	$ 15,397	$ 580,029	$ 8,364	$ (504,773)	$ 99,017
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 13,080	$ 550,278	$ 2,801	$ (517,548)	$ 48,611
Cash Flow and Fair Value Hedges (a)	-	1,770	-	(983)	787
DETM Assignment (c)	-	-	-	3,637	3,637
Total Risk Management Liabilities	$ 13,080	$ 552,048	$ 2,801	$ (514,894)	$ 53,035

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 2,453	$ 29,559	$ 20	$ (26,488)	$ 5,544
Cash Flow and Fair Value Hedges (a)	-	215	-	20	235
Total Risk Management Assets	$ 2,453	$ 29,774	$ 20	$ (26,468)	$ 5,779
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 2,593	$ 28,908	$ 8	$ (26,624)	$ 4,885
Cash Flow and Fair Value Hedges (a)	-	34	-	20	54
DETM Assignment (c)	-	-	-	95	95
Total Risk Management Liabilities	$ 2,593	$ 28,942	$ 8	$ (26,509)	$ 5,034

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,295	$ 39,866	$ 8	$ (36,422)	$ 6,747
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 3,664	$ 37,835	$ 10	$ (36,527)	$ 4,982
DETM Assignment (c)	-	-	-	149	149
Total Risk Management Liabilities	$ 3,664	$ 37,835	$ 10	$ (36,378)	$ 5,131

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 2,891	$ 51,171	$ 31	$ (45,790)	$ 8,303
Cash Flow and Fair Value Hedges (a)	-	291	-	(83)	208
Total Risk Management Assets	$ 2,891	$ 51,462	$ 31	$ (45,873)	$ 8,511
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 3,056	$ 48,767	$ 16	$ (45,961)	$ 5,878
Cash Flow and Fair Value Hedges (a)	-	236	-	(83)	153
DETM Assignment (c)	-	-	-	112	112
Total Risk Management Liabilities	$ 3,056	$ 49,003	$ 16	$ (45,932)	$ 6,143

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,883	$ 61,471	$ 14	$ (55,710)	$ 9,658
Cash Flow and Fair Value Hedges (a)	-	107	-	(80)	27
Total Risk Management Assets	$ 3,883	$ 61,578	$ 14	$ (55,790)	$ 9,685
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,318	$ 58,390	$ 17	$ (55,834)	$ 6,891
Cash Flow and Fair Value Hedges (a)	-	265	-	(80)	185
DETM Assignment (c)	-	-	-	175	175
Total Risk Management Liabilities	$ 4,318	$ 58,655	$ 17	$ (55,739)	$ 7,251

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.
(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.
(c) See "Natural Gas Contracts with DETM" section of Note 15 in the 2008 Annual Report.
(d) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(f) Amounts represent corporate, municipal and treasury bonds.
(g) Amounts represent publicly traded equity securities and equity-based mutual funds.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Three Months Ended June 30, 2009	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of April 1, 2009	$ 11,847	$ 6,294	$ 6,092	$ 7,802	$ 1	$ 2
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(4,739)	(2,514)	(2,432)	(3,103)	3	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	3,878	-	5,065	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(2,419)	(1,283)	(1,241)	(1,589)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	9,211	997	4,716	1,235	8	8
Balance as of June 30, 2009	$ 13,900	$ 7,372	$ 7,135	$ 9,410	$ 12	$ 15

Six Months Ended June 30, 2009	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of January 1, 2009	$ 8,009	$ 4,497	$ 4,352	$ 5,563	$ (2)	$ (3)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(6,200)	(3,482)	(3,369)	(4,301)	3	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	5,466	-	6,907	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(176)	(106)	(97)	6	36	58
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	12,267	997	6,249	1,235	(25)	(45)
Balance as of June 30, 2009	$ 13,900	$ 7,372	$ 7,135	$ 9,410	$ 12	$ 15

Three Months Ended June 30, 2008	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of April 1, 2008	$ (942)	$ (552)	$ (519)	$ (837)	$ (21)	$ (35)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(532)	(324)	(315)	(327)	1	4
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	261	-	161	-	(5)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(2,186)	(1,313)	(1,261)	(1,530)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(14,900)	(9,194)	(8,580)	(10,712)	(3)	(9)
Balance as of June 30, 2008	$ (18,560)	$ (11,122)	$ (10,675)	$ (13,245)	$ (23)	$ (45)

Six Months Ended June 30, 2008	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of January 1, 2008	$ (697)	$ (263)	$ (280)	$ (1,607)	$ (243)	$ (408)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(467)	(339)	(312)	232	98	174
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	(1,138)	-	(2,019)	-	(64)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (b)	(122)	(188)	(158)	861	232	375
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(17,274)	(9,194)	(9,925)	(10,712)	(110)	(122)
Balance as of June 30, 2008	$ (18,560)	$ (11,122)	$ (10,675)	$ (13,245)	$ (23)	$ (45)

(a) Included in revenues on the Statements of Income.
(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

10. 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 tax 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 reflects a separate return result for each company in the consolidated group.

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2000. The Registrant Subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Tax Legislation – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

The American Recovery and Reinvestment Act of 2009 was signed into law by the President in February 2009. It provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions are not expected to have a material impact on net income or financial condition. However, management forecasts the bonus depreciation provision could provide a significant favorable cash flow benefit to the Registrant Subsidiaries in 2009.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2009 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 350,000	7.95	2020
I&M	Senior Unsecured Notes	475,000	7.00	2019
I&M	Pollution Control Bonds	50,000	6.25	2025
I&M	Pollution Control Bonds	50,000	6.25	2025
PSO	Pollution Control Bonds	33,700	5.25	2014

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Senior Unsecured Notes	$ 150,000	6.60	2009
APCo	Land Note	8	13.718	2026
OPCo	Notes Payable	1,000	6.27	2009
OPCo	Notes Payable	6,500	7.21	2009
OPCo	Notes Payable	70,000	7.49	2009
PSO	Senior Unsecured Notes	50,000	4.70	2009
SWEPCo	Notes Payable	2,203	4.47	2011

In January 2009, AEP Parent loaned I&M $25 million of 5.375% Notes Payable due in 2010.

During 2008, the Registrant Subsidiaries chose to begin eliminating their auction-rate debt position due to market conditions. The instruments under which the bonds are issued allow for conversion to other short-term variable-rate structures, term-put structures and fixed-rate structures. As of June 30, 2009, OPCo had $218 million of tax-exempt long-term debt related to JMG that sold at auction rates (rates reset every 35 days). Interest rates on this debt are at the contractual maximum rate of 13%. OPCo was unable to refinance this debt without JMG's consent. To terminate the JMG relationship, OPCo sought approval from the PUCO and received approval in June 2009. OPCo purchased JMG's outstanding equity ownership in July 2009 for $28 million. OPCo plans to refinance the related outstanding debt as market conditions permit. As of June 30, 2009, SWEPCo had $54 million of tax-exempt long-term debt sold at auction rates of 1.122% that reset every 35 days.

Trustees held, on the Registrant Subsidiaries' behalf as shown in the following table, the remaining reacquired auction-rate tax-exempt long-term debt which the Registrant Subsidiaries plan to reissue to the public as market conditions permit.

Company	June 30, 2009 (in thousands)
APCo	$ 17,500
CSPCo	92,245
OPCo	85,000

Utility Money Pool – 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 Utility Money Pool 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, 2009 and December 31, 2008 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, 2009 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of June 30, 2009	Authorized Short-Term Borrowing Limit
	(in thousands)					
APCo	$ 420,925	$ -	$ 202,261	$ -	$ (175,376)	$ 600,000
CSPCo	203,306	-	146,672	-	(162,659)	350,000
I&M	491,107	22,979	122,731	12,724	(2,350)	500,000
OPCo	522,934	55,125	315,813	27,363	40,319	600,000
PSO	77,976	87,443	56,378	37,667	19,438	300,000
SWEPCo	62,871	143,123	19,501	28,466	31,999	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, 2009	Six Months Ended June 30, 2008
Maximum Interest Rate	2.28%	5.37%
Minimum Interest Rate	0.65%	2.91%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2009 and 2008 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Six Months Ended June 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for the Six Months Ended June 30,	
Company	2009	2008	2009	2008
APCo	1.45%	3.86%	-%	3.25%
CSPCo	1.27%	3.66%	-%	2.93%
I&M	1.47%	3.30%	1.71%	-%
OPCo	1.35%	3.39%	0.72%	-%
PSO	2.01%	3.03%	1.31%	4.53%
SWEPCo	1.67%	3.36%	1.38%	2.93%

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		June 30, 2009			December 31, 2008		
Company	Type of Debt	Outstanding Amount (in thousands)		Interest Rate (c)	Outstanding Amount (in thousands)		Interest Rate (c)
SWEPCo	Line of Credit – Sabine Mining Company (a)	$	14,872	1.74%	$	7,172	1.54%
OPCo	Commercial Paper – JMG (b)		11,500	1.25%		-	-

(a) Sabine Mining Company is consolidated under FIN 46R.
(b) This commercial paper was used to pay down debt in the second quarter of 2009 and matured on July 1, 2009.
(c) Weighted average rate.

Credit Facilities

The Registrant Subsidiaries and certain other companies in the AEP System have a $627 million 3-year credit agreement. Under the facility, letters of credit may be issued. As of June 30, 2009, $372 million of letters of credit were issued by Registrant Subsidiaries under the $627 million 3-year credit agreement to support variable rate Pollution Control Bonds as follows:

Company	Letters of Credit Amount Outstanding Against $627 million Agreement (in thousands)	
APCo	$	126,716
I&M		77,886
OPCo		166,899

The Registrant Subsidiaries and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

Sales of Receivables

In July 2009, AEP Credit renewed and increased its sale of receivables agreement. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables. This agreement will expire in July 2010.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income 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 2008 Annual Report should also be read in conjunction with this report.

Economic Slowdown

The Registrant Subsidiaries' residential and commercial KWH sales appear to be stable; nevertheless, some segments of their service territories are experiencing slowdowns. Management is currently monitoring the following:

- Margins from Off-system Sales – Margins from off-system sales for the AEP System continue to decrease due to reductions in sales volumes and weak market power prices, reflecting reduced overall demand for electricity. Management currently forecasts that margins from off-system volumes will decrease by approximately 34% in 2009 in comparison to 2008.

- Industrial KWH Sales – The AEP System's industrial KWH sales for the quarter and six months ended June 30, 2009 were down 21% and 18%, respectively. Approximately half of these decreases were due to cutbacks or closures by customers who produce primary metals served by APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. The Registrant Subsidiaries also experienced additional significant decreases in KWH sales to customers in the plastics and rubber, paper and transportation manufacturing industries. When the economy and export markets recover, management expects to see a return to more normal levels of industrial KWH sales.

- Risk of Loss of Major Customers – Management monitors the financial strength and viability of each major industrial customer individually. The Registrant Subsidiaries factor industrial customer analyses into their operational planning. In July 2009, CSPCo's and OPCo's largest customer, Ormet, a major industrial customer currently operating at a reduced load of approximately 400 MW, announced that it will substantially curtail operations starting in September 2009. In February 2009, Century Aluminum, a major industrial customer (325 MW load) of APCo, announced the curtailment of operations at its Ravenswood, WV facility.

Credit Markets

Although the financial markets remain volatile at both a global and domestic level, the Registrant Subsidiaries issued debt as follows during the first six months of 2009:

Company	Issuance (in millions)
APCo	$ 350
I&M	600
PSO	34

The uncertainties in the capital markets could have significant implications since the Registrant Subsidiaries rely on continuing access to capital to fund operations and capital expenditures.

Management believes that the Registrant Subsidiaries have adequate liquidity, through the Utility Money Pool and cash flows from their operations, to support planned business operations and capital expenditures. Long-term debt of $200 million, $150 million, $680 million and $150 million will mature in 2010 for APCo, CSPCo, OPCo and PSO, respectively. Management intends to refinance or repay debt maturities. Management cannot predict the length of time the current credit situation will continue or its impact on future operations and the Registrant Subsidiaries' ability to issue debt at reasonable interest rates.

Pension, Nuclear Decommissioning and Other Trust Funds

AEP sponsors several trust funds with significant investments intended to provide for future payments of pensions and OPEB. I&M has significant investments in several trust funds intended to provide for future payments of nuclear decommissioning and spent nuclear fuel disposal. Although all of the trust funds' investments are well-diversified and managed in compliance with all laws and regulations, the value of the investments in these trusts declined substantially over the past year due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. The decline in pension asset values will not require the AEP System to make a contribution under ERISA in 2009. Management estimates that the minimum contributions to the pension trust will be $453 million in 2010 and $292 million in 2011. These amounts are allocated to companies in the AEP System, including the Registrant Subsidiaries. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

Risk Management Contracts

On behalf of the Registrant Subsidiaries, AEPSC enters into risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. AEP's risk management organization monitors these exposures on a daily basis to limit the Registrant Subsidiaries' economic and financial statement impact on a counterparty basis.

Budgeted Construction Expenditures

Budgeted construction expenditures excluding AFUDC for the Registrant Subsidiaries for 2010 are:

Company	Budgeted Construction Expenditures (in millions)	
APCo	$ 297	
CSPCo	231	
I&M	246	
OPCo	294	
PSO	162	
SWEPCo	423	(a)

(a) Includes $212 million and $35 million in budgeted capital expenditures related to the Turk Plant and Stall Unit, respectively.

Budgeted 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.

LIQUIDITY

Sources of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities through the Utility Money Pool. AEP and its Registrant Subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity. In March 2008, these credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit (LOC). The Registrant Subsidiaries generally use short-term funding sources (the Utility Money Pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leasebacks, leasing arrangements and additional capital contributions from Parent.

The Registrant Subsidiaries and certain other companies in the AEP System entered into a $627 million 3-year credit agreement. The Registrant Subsidiaries may issue LOCs under the credit facility. Each subsidiary has a borrowing/LOC limit under the credit facility. As of June 30, 2009, a total of $372 million of LOCs were issued under the 3-year credit agreement to support variable rate demand notes. The following table shows each Registrant Subsidiaries' borrowing/LOC limit under the credit facility and the outstanding amount of LOCs.

Company	$627 million Credit Facility Borrowing/LOC Limit	LOC Amount Outstanding Against $627 million Agreement at June 30, 2009
	(in millions)	
APCo	$ 300	$ 127
CSPCo	230	-
I&M	230	78
OPCo	400	167
PSO	65	-
SWEPCo	230	-

Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.

Sale of Receivables Through AEP Credit

In July 2009, AEP Credit renewed and increased its sale of receivables agreement through July 2010. The sale of receivables agreement provides a commitment of $750 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Management intends to extend or replace the sale of receivables agreement. At June 30, 2009, $596 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit purchases accounts receivable from the Registrant Subsidiaries.

SIGNIFICANT FACTORS

Ohio Electric Security Plan Filings

In July 2008, as required by the 2008 amendments to the Ohio restructuring legislation, CSPCo and OPCo filed ESPs with the PUCO to establish standard service offer rates. In March 2009, the PUCO issued an order, which was amended by a rehearing entry in July 2009, that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases through a phase-in of the FAC. The capped increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. CSPCo and OPCo implemented rates for the April 2009 billing cycle. In its July 2009 rehearing entry, the PUCO required CSPCo and OPCo to reduce rates implemented in April 2009 by $22 million and $27 million, respectively, on an annualized basis. CSPCo and OPCo are collecting the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to meet the ordered annual caps described above. The FAC increase before phase-in will be subject to quarterly true-ups to actual recoverable FAC costs and to annual accounting audits and prudency reviews. The order allows CSPCo and OPCo to defer unrecovered FAC costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

As of June 30, 2009, the recognized revenues and the FAC deferrals were adjusted to reflect the PUCO's July 2009 rehearing entry, which among other things, reversed the prior authorization to recover the cost of CSPCo's recently acquired Waterford and Darby Plants. In July 2009, CSPCo filed an application for rehearing with the PUCO seeking authorization to sell or transfer the Waterford and Darby Plants. The FAC deferrals after adjustment at June 30, 2009 were $34 million and $140 million for CSPCo and OPCo, respectively, including carrying charges. The PUCO rejected a proposal by several intervenors to offset the FAC costs with a credit for off-system sales margins. As a result, CSPCo and OPCo will retain the benefit of their share of the AEP System's off-system sales.

Consistent with its decisions on ESP orders of other companies, the PUCO ordered its staff to convene a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET) that will be applicable to all electric utilities in Ohio. The SEET requires the PUCO to determine, following the end of each year of the ESP, if any rate adjustments included in the ESP resulted in excessive earnings. This is determined by measuring whether the earned return on common equity of CSPCo and OPCo is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, which have comparable business and financial risk. In the March 2009 order, the PUCO determined that off-system sales margins and FAC deferral credits and associated costs should be excluded from the SEET methodology. The July 2009 PUCO rehearing entry deferred those issues to the SEET workshop. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the PUCO must require that the excess amount be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until a SEET filing is made in 2010 and the PUCO issues an order thereon.

In March 2009, intervenors filed a motion to stay a portion of the ESP rates or alternately make that portion subject to refund because the intervenors believed that the ordered ESP rates for 2009 were retroactive and therefore unlawful. In March 2009, the PUCO approved CSPCo's and OPCo's tariffs effective with the April 2009 billing cycle and rejected the intervenors' motion. The PUCO also clarified that the reference in its earlier order to the January 1, 2009 date related to the term of the ESP and not to the effective date of tariffs and clarified the tariffs were not retroactive. In the rehearing entry, the PUCO reaffirmed its holding that it had not authorized retroactive rates.

In April 2009, certain intervenors filed a complaint for writ of prohibition with the Ohio Supreme Court to halt any further collection from customers of what the intervenors claim is unlawful retroactive rate increases. In May 2009, CSPCo, OPCo and the PUCO filed a motion to dismiss the writ of prohibition. In June 2009, the Ohio Supreme Court dismissed the writ of prohibition.

In June 2009, intervenors filed a motion in the ESP proceeding with the PUCO requesting CSPCo and OPCo to refund deferrals allegedly collected by CSPCo and OPCo which were created by the PUCO's approval of a temporary special arrangement between CSPCo, OPCo and Ormet, a large industrial customer. In addition, the intervenors requested that the PUCO prevent CSPCo and OPCo from collecting these revenues in the future. In June 2009, CSPCo and OPCo filed its response regarding the motion to refund amounts allegedly collected and to prevent future collections. The CSPCo and OPCo response noted that the difference in the amount deferred between the PUCO-determined market price for 2008 and the rate paid by Ormet was not collected, but instead was deferred, with PUCO authorization, as a regulatory asset for future recovery. In the rehearing entry, the PUCO did not order an adjustment to rates based on this issue.

New Generation/Purchase Power Agreement

In 2009, AEP is in various stages of construction of the following generation facilities:

Operating Company	Project Name		Location	Total Projected Cost (a)	CWIP (b)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
				(in millions)	(in millions)				
AEGCo	Dresden	(c)	Ohio	$ 321	$ 198	Gas	Combined-cycle	580	2013
SWEPCo	Stall		Louisiana	384	322	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(d)	Arkansas	1,628(d)	560(e)	Coal	Ultra-supercritical	600(d)	2012
APCo	Mountaineer	(f)	West Virginia	(f)		Coal	IGCC	629	(f)
CSPCo/OPCo	Great Bend	(f)	Ohio	(f)		Coal	IGCC	629	(f)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(d) SWEPCo owns approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. See "Turk Plant" section below.
(e) Amount represents SWEPCo's CWIP balance only.
(f) Construction of IGCC plants is subject to regulatory approvals. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval for SWEPCo to build the Turk Plant in Arkansas at the existing site by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Certain intervenors appealed the APSC's decision to grant the CECPN to build the Turk Plant to the Arkansas Court of Appeals. In January 2009, the APSC granted additional CECPNs allowing SWEPCo to construct Turk-related transmission facilities. Intervenors also appealed these CECPN orders to the Arkansas Court of Appeals.

In June 2009, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN permitting construction of the Turk Plant to serve Arkansas retail customers. The decision was based upon the Arkansas Court of Appeals' interpretation of the statute that governs the certification process and its conclusion that the APSC did not fully comply with that process. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the generating plant and the proposed transmission facilities' construction and location should all have been considered by the APSC in a single docket instead of separate dockets. Both SWEPCo and the APSC petitioned the Arkansas Supreme Court to review the Arkansas Court of Appeals decision. SWEPCo's petition for review had the effect of staying the Arkansas Court of Appeals decision and, while the appeals are pending, SWEPCo is continuing construction of the Turk Plant. Management believes that the APSC properly interpreted and applied the Arkansas statutes governing the Turk Plant certification process and that SWEPCo's grounds for seeking review are strong.

If the decision of the Court of Appeals is not reversed by the Supreme Court of Arkansas, SWEPCo and the other joint owners of the Turk Plant will evaluate their options. Depending on the time taken by the Arkansas Supreme Court to consider the case and the reasoning of the Arkansas Supreme Court when it acts on SWEPCo's and the APSC's petitions, the construction schedule and/or the cost could be adversely affected. Should the appeal be unsuccessful, additional proceedings or alternative contractual, ownership and operational responsibilities could be required.

In March 2008, the LPSC approved the application to construct the Turk Plant. In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions as being unlawful. If the cost cap restrictions are upheld and construction or CO_2 emission costs exceed the restrictions, it could have an adverse effect on net income, cash flows and possibly financial condition. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in Federal District Court by certain Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals. In January 2009, SWEPCo filed a motion to dismiss the appeal, which was granted in March 2009.

In November 2008, SWEPCo received the required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. In December 2008, certain parties filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while the appeal of the Turk Plant's permit is heard. In June 2009, hearings on the air permit appeal were held at the APCEC. A decision is still pending and not expected until 2010. These same parties have filed a petition with the Federal EPA to review the air permit. If the air permit were to be remanded or ultimately revoked, construction of the Turk Plant could be suspended or cancelled. The Turk Plant cannot be placed into service without an air permit.

SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. In March 2009, SWEPCo reported to the U.S. Army Corps of Engineers an inadvertent impact on approximately 2.5 acres of wetlands at the Turk Plant construction site prior to the receipt of the permit. The U.S. Army Corps of Engineers directed SWEPCo to cease further work impacting the wetland areas. Construction has continued on other areas outside of the proposed Army Corps of Engineers permitted areas of the Turk Plant pending the Army Corps of Engineers review. SWEPCo has entered into a Consent Agreement and Final Order with the Federal EPA to resolve liability for the inadvertent impact and agreed to pay a civil penalty of approximately $29 thousand.

The Arkansas Governor's Commission on Global Warming issued its final report to the governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. To date, the report's effect is only advisory, but if legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's ability to complete construction on schedule in 2012 and on budget.

If the Turk Plant cannot be completed and placed in service, SWEPCo would seek approval to recover its prudently incurred capitalized construction costs including any cancellation fees and a return on unrecovered balances through rates in all of its jurisdictions. As of June 30, 2009, and excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $570 million of expenditures (including AFUDC and related transmission costs of $10 million) and has contractual construction commitments for an additional $582 million (including related transmission costs of $7 million). As of June 30, 2009, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $136 million (including related transmission cancellation fees of $1 million).

Management believes that SWEPCo's planning, certification and construction of the Turk Plant to date have been in material compliance with all applicable laws and regulations, except for the inadvertent wetlands intrusion discussed above. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if for any reason SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would adversely impact net income, cash flows and possibly financial condition unless the resultant losses can be fully recovered, with a return on unrecovered balances, through rates in all of its jurisdictions.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through June 2009, APCo deferred for future recovery preconstruction IGCC costs of $20 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all pre-construction cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction, it would have an adverse effect on future net income and cash flows.

PSO Purchase Power Agreement

PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, executed a long-term purchase power agreement (PPA) for which an application seeking its approval was filed with the OCC in May 2009. The PPA is for the purchase of up to 520 MW of electric generation from the 795 MW natural gas-fired Green Country Generating Station, located in Jenks, Oklahoma. The agreement is the result of PSO's 2008 Request for Proposals following a December 2007 OCC order that found PSO had a need for new base load generation by 2012. In July 2009, OCC staff, the Independent Evaluator and the Oklahoma Industrial Energy Consumers filed responsive testimony in support of PSO's proposed PPA with Exelon. An order from the OCC is expected before year-end 2009.

The American Recovery and Reinvestment Act of 2009

The American Recovery and Reinvestment Act of 2009 was signed into law by the President in February 2009. It provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions are not expected to have a material impact on net income or financial condition. However, management forecasts the bonus depreciation provision could provide a significant favorable cash flow benefit to the Registrant Subsidiaries in 2009 as follows:

Company	Amount (in millions)
APCo	$ 53
CSPCo	38
I&M	54
OPCo	38
PSO	27
SWEPCo	25

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 CAA to reduce emissions of SO_2, 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 is also involved in the development of possible future requirements to reduce CO_2 and other greenhouse gases (GHG) 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 2008 Annual Report.

Clean Water Act Regulation

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 the AEP System's 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

In 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. The Registrant Subsidiaries sought further review and filed for relief from the schedules included in their permits.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. Management cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states.

Potential Regulation of CO_2 and Other GHG Emissions

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act (ACES). ACES is a comprehensive energy and climate change bill that includes a number of provisions that would directly affect the Registrant Subsidiaries' business. ACES contains a combined energy efficiency and renewable electricity standard beginning at 6% in 2012 and increasing to 20% by 2020 of retail sales. The proposed legislation would also create a carbon capture and sequestration program funded through rates to accelerate the development of this technology and establishes GHG emission standards for new fossil fuel-fired electric generating plants. ACES creates an economy-wide cap and trade program for large sources of GHG emissions that would reduce emissions by 17% in 2020 and just over 80% by 2050 from 2005 levels. A portion of the allowances under the cap and trade program would be allocated to retail electric and gas utilities, certain energy-intensive industries, small refiners and state governments. Some allowances would be auctioned. Bonus allowances would be available to encourage energy efficiency, renewable energy and carbon sequestration projects. Consideration of climate legislation has now moved to the Senate. Until legislation is final, management is unable to predict its impact on net income, cash flows and financial condition.

In April 2009, the Federal EPA issued a proposed endangerment finding under the CAA regarding GHG emissions from motor vehicles. The proposed endangerment finding is subject to public comment. This finding could lead to regulation of CO_2 and other gases under existing laws. Congress continues to discuss new legislation related to the control of these emissions. Some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including the AEP System. Because of these adverse consequences, management believes that these more extreme policies will not ultimately be adopted. Even if reasonable CO_2 and other GHG emission standards are imposed, they will still require the Registrant Subsidiaries to make material expenditures. Management believes that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers, and should be recoverable from customers as costs of doing business including capital investments with a return on investment.

Adoption of New Accounting Pronouncements

The FASB issued SFAS 141R "Business Combinations" improving financial reporting about business combinations and their effects and FSP SFAS 141 (R)-1. SFAS 141R can affect tax positions on previous acquisitions. The Registrant Subsidiaries do not have any such tax positions that result in adjustments. The Registrant Subsidiaries adopted SFAS 141R, including the FSP, effective January 1, 2009. The Registrant Subsidiaries will apply it to any future business combinations.

The FASB issued SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. The Registrant Subsidiaries adopted SFAS 160 retrospectively effective January 1, 2009. See Note 2.

The FASB issued SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard increased disclosure requirements related to derivative instruments and hedging activities in future reports. The Registrant Subsidiaries adopted SFAS 161 effective January 1, 2009.

The FASB issued SFAS 165 "Subsequent Events" (SFAS 165), incorporating guidance on subsequent events into authoritative accounting literature and clarifying the time following the balance sheet date which management reviewed for events and transactions that may require disclosure in the financial statements. The Registrant Subsidiaries adopted this standard effective second quarter of 2009. The standard increased disclosure by requiring disclosure of the date through which subsequent events have been reviewed. The standard did not change management's procedures for reviewing subsequent events.

The FASB ratified EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5) a consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. The Registrant Subsidiaries adopted EITF 08-5 effective January 1, 2009. With the adoption of FSP SFAS 107-1 and APB 28-1, it is applied to the fair value of long-term debt. The application of this standard had an immaterial effect on the fair value of debt outstanding.

The FASB ratified EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. The Registrant Subsidiaries prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on their financial statements.

The FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments. The Registrant Subsidiaries adopted the standard effective second quarter of 2009. This standard increased the disclosure requirements related to financial instruments.

The FASB issued FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments", amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements. The Registrant Subsidiaries adopted the standard effective second quarter of 2009 with no impact on financial statements and increased disclosure requirements related to financial instruments for I&M only.

The FASB issued FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The Registrant Subsidiaries adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

The FASB issued SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2), which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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. The Registrant Subsidiaries adopted SFAS 157-2 effective January 1, 2009. The Registrant Subsidiaries will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. The Registrant Subsidiaries did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first six months of 2009.

The FASB issued FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4), providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods. The Registrant Subsidiaries adopted the standard effective second quarter of 2009. This standard had no impact on the financial statements but increased disclosure requirements.

CONTROLS AND PROCEDURES

During the second quarter of 2009, 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, 2009, 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 2009 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 "Commitments, Guarantees and Contingencies" section of Note 4 incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2008 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 2008 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Turk Plant permits could be reversed on appeal. *(Applies to AEP and SWEPCo)*

In November 2007, the APSC granted approval for SWEPCo to build the Turk Plant in Arkansas by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Certain intervenors appealed the APSC's decision to the Arkansas Court of Appeals. In June 2009, the Arkansas Court of Appeals issued a unanimous decision which would reverse, if upheld by the Arkansas Supreme Court, the APSC's grant of the CECPN permitting construction of the Turk Plant to serve Arkansas retail customers. Both SWEPCo and the APSC petitioned the Arkansas Supreme Court to review the Arkansas Court of Appeals decision.

In November 2008, SWEPCo received the required air permit approval for the Turk Plant from the Arkansas Department of Environmental Quality. In December 2008, certain parties filed an appeal with the Arkansas Pollution Control and Ecology Commission. A decision on the air permit is still pending and not expected until 2010. These same parties have filed a petition with the Federal EPA to review the air permit. The Turk Plant cannot operate without an air permit. If SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would adversely impact net income, cash flow and possibly financial condition unless the resultant losses can be fully recovered, with a return on unrecovered balances, through rates in all of it jurisdictions.

Rate recovery approved in Ohio may be overturned on appeal or may not provide full recovery of fuel costs. *(Applies to AEP, OPCo and CSPCo)*

In March 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs. The ESPs will be in effect through 2011. The ESP order authorized increases to revenues during the ESP period and capped the overall revenue increases. The ordered rate cap increases for CSPCo are 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo are 8% in 2009, 7% in 2010 and 8% in 2011. The order provides for the recovery of fuel costs incurred during the three-year period of the ESP. The order allows CSPCo and OPCo to defer unrecovered fuel costs resulting from the annual caps/phase-in plan and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred fuel cost balance at the end of the ESP period is to be recovered through a non-bypassable surcharge over the period 2012 through 2018. In April 2009, several intervenors filed motions requesting rehearing of issues underlying the PUCO's authorized rate increase and one intervenor filed a motion requesting the PUCO to direct CSPCo and OPCo to cease collecting rates under the order. If the PUCO reverses all or part of the rate recovery or if deferred fuel costs are not fully recovered for other reasons, it could have an adverse effect on future net income, cash flows and financial condition.

Rate recovery approved in Texas may be overturned on appeal. *(Applies to AEP)*

In March 2008, the PUCT issued an order approving a $20 million base rate increase based on a return on common equity of 9.96% and an additional $20 million increase in revenues related to the expiration of TCC's merger credits. In addition, depreciation expense was decreased by $7 million and discretionary fee revenues were increased by $3 million. TCC estimates the order will increase TCC's annual pretax income by $50 million. Various parties appealed the PUCT decision.

In February 2009, the Texas District Court affirmed the PUCT in most respects. In March 2009, various intervenors appealed the Texas District Court decision to the Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the PUCT and/or the Texas Court of Appeals reverse all or part of the rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Our request for rate recovery in Virginia may not be approved in its entirety. *(Applies to AEP and APCo)*

In July 2009, APCo filed a base rate case with the Virginia SCC requesting an increase in the generation and distribution portions of base rates of $169 million annually and a 13.35% return on equity. If the Virginia SCC denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Rate recovery approved in Oklahoma may be overturned on appeal. *(Applies to AEP and PSO)*

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues and a 10.5% return on equity. In February 2009, the Oklahoma Attorney General and several intervenors filed appeals with the Oklahoma Supreme Court raising several issues. If the OCC and/or the Oklahoma Supreme Court reverse all or part of the rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Our request for rate recovery in Arkansas may not be approved in its entirety. *(Applies to AEP and SWEPCo)*

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to concurrently recover financing costs related to the Stall and Turk construction projects. If the APSC denies all or part of the requested rate recovery, it could have an adverse effect on future net income, cash flows and financial condition.

Risks Related to Market, Economic or Financial Volatility

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant)*

Since the bankruptcy of Enron, the credit ratings agencies have periodically reviewed our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future net income could be adversely affected.

If Moody's or S&P were to downgrade the long-term rating of any of the securities of the registrants, particularly below investment grade, the borrowing costs of that registrant would increase, which would diminish its financial results. In addition, the registrant's potential pool of investors and funding sources could decrease. In 2009, Fitch downgraded the senior unsecured debt rating of I&M to BBB with stable outlook and changed its rating outlook for SWEPCo from stable to negative. In 2009, Moody's downgraded SWEPCo to Baa3 with stable outlook and changed the rating outlook for APCo from negative to stable.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

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, 2009 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
04/01/09 – 04/30/09	49(a)	$ 61.60	-	$ -
05/01/09 – 05/31/09	-	-	-	-
06/01/09 – 06/30/09	-	-	-	-

(a) PSO purchased 40 shares of its 4% cumulative preferred stock in a privately-negotiated transaction outside of an announced program. OPCo repurchased 9 shares of its 4.5% cumulative preferred stock in a privately-negotiated transaction outside of an announced program.

Item 4. Submission Matters to a Vote of Security Holders

AEP

The annual meeting of shareholders was held in Austin, Texas, on April 28, 2009. 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 twelve 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	302,115,714	28,936,623
Donald M. Carlton	309,121,737	21,930,600
Ralph D. Crosby, Jr.	309,357,886	21,694,451
Linda A. Goodspeed	312,588,927	18,463,410
Thomas E. Hoaglin	284,524,087	46,528,250
Lester A. Hudson, Jr.	308,886,821	22,165,516
Michael G. Morris	303,317,065	27,735,272
Lionel L. Nowell, III	299,943,908	31,108,429
Richard L. Sandor	312,500,835	18,551,502
Kathryn D. Sullivan	312,442,550	18,609,787
Sara M. Tucker	327,027,667	4,024,670
John F. Turner	325,347,483	5,704,854

2. Approval of Amendment to Certificate of Incorporation. The amendment was approved by a vote of the shareholders as follows:

Shares Voted FOR	239,498,852
Shares Voted AGAINST	20,977,190
Shares ABSTAINING	2,538,124

3. Ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm for 2009. The proposal was approved by a vote of the shareholders as follows:

Shares Voted FOR	326,890,110
Shares Voted AGAINST	3,466,843
Shares ABSTAINING	695,384

APCo

The annual meeting of stockholders was held on May 5, 2009 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 13,499,500 votes were cast for each of the following ten persons for election as directors to hold office for one year and until their successors are elected and qualify:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Richard E. Munczinski
Jack B. Keane	Brian X. Tierney
Holly K. Koeppel	Susan Tomasky
Michael G. Morris	Dennis E. Welch

CSPCo

Pursuant to an Action by Written Consent in Lieu of Annual Meeting of the Sole Shareholder dated April 28, 2009, the following ten persons were elected directors:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Richard E. Munczinski
Jack B. Keane	Brian X. Tierney
Holly K. Koeppel	Susan Tomasky
Michael G. Morris	Dennis E. Welch

I&M

Pursuant to an Action by Written Consent in Lieu of Annual Meeting of the Sole Shareholder dated April 28, 2009, the following fifteen persons were elected directors:

Nicholas K. Akins	JoAnn M. Grevenow	Michael G. Morris
Kent D. Curry	Patrick C. Hale	Helen J. Murray
J. Edward Ehler	Holly K. Koeppel	Robert P. Powers
Carl L. English	Marc E. Lewis	Brian X. Tierney
Allen R. Glassburn	Susanne M. Moorman Rowe	Susan Tomasky

OPCo

The annual meeting of stockholders was held on May 5, 2009, at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 27,952,473 votes were cast for each of the following ten persons for election as directors to hold office for one year and until their successors are elected and qualify:

Nicholas K. Akins	Robert P. Powers
Carl L. English	Richard E. Munczinski
Jack B. Keane	Brian X. Tierney
Holly K. Koeppel	Susan Tomasky
Michael G. Morris	Dennis E. Welch

PSO

The annual meeting of stockholders was held on May 5, 2009 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 9,013,000 votes were cast for each of the following ten persons for election as directors to hold office for one year and until their successors are elected and qualify:

Nicholas K. Akins	Michael G. Morris
Carl L. English	Richard E. Munczinski
Jack B. Keane	Robert P. Powers
Holly K. Koeppel	Susan Tomasky
Venita McCellon-Allen	Dennis E. Welch

SWEPCo

The annual meeting of stockholders was held on May 5, 2009 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 7,536,640 votes were cast for each of the following ten persons for election as directors to hold office for one year and until their successors are elected and qualify:

Nicholas K. Akins	Michael G. Morris
Carl L. English	Richard E. Munczinski
Jack B. Keane	Robert P. Powers
Holly K. Koeppel	Susan Tomasky
Venita McCellon-Allen	Dennis E. Welch

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b) – Certification of 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 4, 2009