AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 30, 2009
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 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 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 have 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 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 October 28, 2009
American Electric Power Company, Inc.	477,658,465 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Columbus Southern Power Company	16,410,426 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
September 30, 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.
ASU	Accounting Standards Update issued by the Financial Accounting Standards Board.
CAA	Clean Air Act.
CO2	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 a consolidated variable interest entity.
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 captive insurance company that is a consolidated variable interest entity.
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.
EPS	Earnings Per Share.
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.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FSP	FASB Staff Position.
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.
GHG	Greenhouse gases.
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.
NOx	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.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
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.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
REP	Texas Retail Electric Provider.
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 157	Statement of Financial Accounting Standards No. 157, “Fair Value Measurements.”
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO2	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.
VIE	Variable Interest Entity.
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 necessary 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 that could impact the continued operation of our plants.
- 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 the dispute with Bank of America).
- 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 and demand 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.

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

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. For the first nine months of 2009 in comparison to the first nine months of 2008, off-system sales volumes decreased by 58%.

- Industrial KWH Sales - Industrial KWH sales for both the three months and nine months ended September 30, 2009 were down 17%. Approximately half of the decrease in the first nine months of 2009 was due to cutbacks or closures by 10 of our large metals producing customers. We also experienced continued significant decreases in KWH sales to customers in the transportation, plastics, rubber and paper manufacturing industries.

- Risk of Loss of Major Industrial Customers - We maintain close contact with each of our major industrial customers individually with respect to their expected electric needs. We factor our industrial customer analyses into our operational planning. In September 2009, Ormet, a major industrial customer currently operating at a reduced load of approximately 330 MW (Ormet operated at an approximate 500 MW load in 2008), announced that it will continue operations at this reduced level at least through the end of 2009.

Regulatory Activity

Our significant 2009 rate proceedings include:

- Arkansas - In September 2009, SWEPCo reached a rate change settlement agreement that provides for an $18 million increase in revenues based upon a return on equity of 10.25% and a decrease in annual depreciation rates of $10 million. The combination of these factors should contribute an additional $28 million in annual pretax income to SWEPCo annually. The settlement agreement also includes a separate rider of approximately $11 million annually for the recovery of carrying costs, depreciation and operation and maintenance expenses on the Stall Unit once it is placed in service as expected in mid-2010. Approval of the settlement by the APSC is expected in the fourth quarter of 2009.

- Indiana - In March 2009, the IURC approved a modified rate settlement agreement that provides 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 deferrals from 2009 through 2011. These deferrals will be collected through a non-bypassable surcharge from 2012 through 2018.

- Oklahoma - In October 2009, all but two of the parties to PSO's Capital Reliability Rider filing agreed to a stipulation that was filed with the OCC for PSO to collect no more than $30 million under the CRR on an annual basis beginning January 2010 until PSO's next base rate order.

- Texas - In August 2009, SWEPCo filed a rate case with the PUCT to increase non-fuel base rates by approximately $75 million annually including return on equity of 11.5%. The filing includes financing cost riders of $32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $27 million. The proposed filing would increase SWEPCo's annual pretax income by approximately $51 million.

- Virginia - In July 2009, APCo requested a base rate increase with the Virginia SCC of $169 million annually (later adjusted to $154 million) based on a 13.35% return on common equity. The new rates will become effective, subject to refund, no later than December 2009.

  In August 2009, the Virginia SCC issued an order which provides for a $130 million fuel revenue increase. If actual fuel costs are greater or less than the projected fuel costs, APCo will seek appropriate adjustments in APCo's next fuel factor proceeding.

- West Virginia - In September 2009, the WVPSC issued an order granting a $355 million increase over a four-year phase-in period. The order lowered annual coal cost projections by $27 million and deferred recovery of unrecovered ENEC deferrals related to price increases on certain renegotiated coal contracts. The WVPSC indicated that it would review the prudency of these additional costs in the next ENEC proceeding and APCo will adjust rates appropriately.

Mountaineer Carbon Capture and Storage Project

In January 2008, APCo and ALSTOM Power, Inc., an unrelated third party, entered into an agreement to jointly construct a CO2 capture demonstration facility. APCo will also construct and own the necessary facilities to store CO2. APCo's combined estimated cost for its necessary storage facilities and its share of the CO2 capture demonstration facility is $74 million. In September 2009, the capture portion of the project was placed into service and in October 2009, APCo started injecting CO2 successfully in underground storage.

In August 2009, APCo applied for federal grant funding for a new commercial project at the 1,300 MW Mountaineer Plant to capture and store carbon for 235 MW of generation by 2015. The total cost of this proposed project is currently estimated to be $668 million.

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. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals decision. While the appeal is pending, SWEPCo is continuing construction of the Turk Plant.

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 of the air permit approval 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 the Federal EPA to review the air permit. The petition will be acted on by December 2009, according to the terms of a recent settlement between the petitioners and the Federal EPA. The Turk Plant cannot be placed in service without an air permit.

Pension Trust Fund

Recent recovery in our pension asset values and the IRS modification of interest calculation rules reduced our estimated 2010 contribution for both qualified and nonqualified pension plans to $62 million from our previously disclosed estimated contribution of $453 million. The present estimated contribution for both qualified and nonqualified pension plans for 2011 is $389 million. These estimates may vary significantly based on market returns, changes in actuarial assumptions, management discretion to contribute more than the minimum requirement 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 September 30, 2009, our credit exposure net of collateral was approximately $886 million of which approximately 88% is to investment grade counterparties. At September 30, 2009, our exposure to financial institutions was $26 million (all investment grade), which represents 3% of our total credit exposure net of collateral.

Capital Expenditures

In October 2009, we revised our 2010 capital expenditure budget for our Utility Operations segment from $1,846 million to $1,993 million primarily as a result of deferring 2009 expenditures to 2010.

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 continued 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, carrying costs and cash.

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 nine months ended September 30, 2009 and 2008.

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions)			
Utility Operations	$ 448	$ 359	$ 1,121	$ 1,036
AEP River Operations	10	11	22	21
Generation and Marketing	5	16	33	43
All Other (a)	(17)	(10)	(45)	133
Income Before Discontinued Operations and Extraordinary Loss	$ 446	$ 376	$ 1,131	$ 1,233

(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

Third Quarter of 2009 Compared to Third Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 increased $70 million compared to 2008 primarily due to an increase in Utility Operations segment earnings of $89 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 retail sales volumes as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 477 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 September 30, 2009.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $102 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. For our Utility Operations segment, Income Before Discontinued Operations and Extraordinary Loss increased $85 million primarily due to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower retail sales volumes as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 452 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 September 30, 2009.

Utility Operations

Our Utility Operations segment primarily includes 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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Revenues	$3,389	$3,968	$9,712	$10,575
Fuel and Purchased Power	1,145	1,841	3,337	4,428
Gross Margin	2,244	2,127	6,375	6,147
Depreciation and Amortization	412	379	1,173	1,099
Other Operating Expenses	988	1,034	2,975	3,001
Operating Income	844	714	2,227	2,047
Other Income, Net	42	47	97	138
Interest Expense	232	224	679	650
Income Tax Expense	206	178	524	499
Income Before Discontinued Operations and Extraordinary Loss	$448	$359	$1,121	$1,036

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Energy/Delivery Summary	2009	2008	2009	2008
	(in millions of KWH)			

Retail:				
Residential	15,967	15,965	44,731	44,986
Commercial	13,569	13,731	37,773	38,099
Industrial	13,641	16,409	40,564	48,915
Miscellaneous	800	846	2,289	2,381
Total Retail (a)	43,977	46,951	125,357	134,381
Wholesale	8,289	13,165	22,233	35,904
Total KWHs	52,266	60,116	147,590	170,285

(a) Energy delivered to customers served by AEP's Texas Wires Companies.

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 nine months ended September 30, 2009 and 2008 were as follows:

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
		(in degree days)		
Weather Summary				
Eastern Region				
Actual – Heating (a)	6	-	2,062	1,966
Normal – Heating (b)	7	7	1,969	1,950
Actual – Cooling (c)	509	659	813	936
Normal – Cooling (b)	703	687	993	969
Western Region (d)				
Actual – Heating (a)	-	-	902	981
Normal – Heating (b)	2	2	941	967
Actual – Cooling (c)	1,170	1,251	1,878	1,955
Normal – Cooling (b)	1,401	1,402	2,080	2,074

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

Third Quarter of 2009 Compared to Third Quarter of 2008

Reconciliation of Third Quarter of 2008 to Third Quarter of 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss

(in millions)

Third Quarter of 2008		$359
Changes in Gross Margin:		
Retail Margins	281	
Off-system Sales	(226)	
Transmission Revenues	10	
Other Revenues	52	
Total Change in Gross Margin		117
Total Expenses and Other:		
Other Operation and Maintenance	52	
Gain on Sales of Assets, Net	(2)	
Depreciation and Amortization	(33)	
Taxes Other Than Income Taxes	(4)	
Interest and Investment Income	(8)	
Carrying Costs Income	(9)	
Allowance for Equity Funds Used During Construction	12	
Interest Expense	(8)	
Total Expenses and Other		-
Income Tax Expense		(28)
Third Quarter of 2009		$448

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 $281 million primarily due to the following:
  - An $87 million increase related to the PUCO's approval of our Ohio ESPs, a $43 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $22 million increase in base rates in Oklahoma and a $7 million net rate increase for I&M.
  - A $151 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 deferral and recovery of fuel and related costs during the ESP period. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $90 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.

  These increases were partially offset by:
  - A $61 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 $42 million decrease in usage primarily due to a 23% decrease in cooling degree days in our eastern region.
  - A $19 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 $226 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 and marketing margins.
- Transmission Revenues increased $10 million primarily due to increased rates in the ERCOT and SPP regions.
- Other Revenues increased $52 million primarily due to Cook Plant accidental outage insurance policy proceeds of $46 million. Of these insurance proceeds, $19 million were used to reduce customer bills. 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 $52 million primarily due to the following:
  - A $37 million decrease in storm restoration expenses.
  - A $23 million decrease in plant operating and maintenance expenses.
  - A $10 million decrease in transmission expense including lower forestry expenses, RTO fees and reliability expenses.
  - An $8 million decrease related to the establishment of a regulatory asset in Virginia for the deferral of transmission costs.
  - A $7 million decrease in customer service expenses.

  These decreases were partially offset by:
  - A $30 million increase in administrative and general expenses, primarily employee medical expenses.
  - An $11 million increase in distribution reliability and other expenses.
- Depreciation and Amortization increased $33 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 $8 million primarily due to the 2008 favorable effect of interest income related to federal income tax refunds filed with the IRS.
- Carrying Costs Income decreased $9 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 $12 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance 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 $8 million primarily due to increased long-term debt.
- Income Tax Expense increased $28 million primarily due to an increase in pretax income, partially offset by state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

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

Nine Months Ended September 30, 2008		$1,036
Changes in Gross Margin:		
Retail Margins	570	
Off-system Sales	(517)	

Transmission Revenues	22	
Other Revenues	153	
Total Change in Gross Margin		228
Total Expenses and Other:		
Other Operation and Maintenance	31	
Gain on Sales of Assets, Net	(1)	
Depreciation and Amortization	(74)	
Taxes Other Than Income Taxes	(4)	
Interest and Investment Income	(37)	
Carrying Costs Income	(31)	
Allowance for Equity Funds Used During Construction	27	
Interest Expense	(29)	
Total Expenses and Other		(118)
Income Tax Expense		(25)
Nine Months Ended September 30, 2009		$1,121

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 $570 million primarily due to the following:
  · A $183 million increase related to the PUCO's approval of our Ohio ESPs, a $147 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $63 million increase in base rates in Oklahoma and a $32 million net rate increase for I&M.
  · A $207 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 $199 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 deferral and 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:
  · A $150 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 $59 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 $34 million decrease in usage primarily due to a 13% decrease in cooling degree days in our eastern region.
  · A $29 million decrease related to favorable coal contract amendments in 2008.

· Margins from Off-system Sales decreased $517 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 and marketing margins.

- Transmission Revenues increased $22 million primarily due to increased rates in the ERCOT and SPP regions.
- Other Revenues increased $153 million primarily due to Cook Plant accidental outage insurance policy proceeds of $145 million. Of these insurance proceeds, $59 million were used to reduce customer bills. 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 $31 million primarily due to the following:
  - An $80 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $55 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.

  These decreases were partially offset by:
  - 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 $37 million increase in administrative and general expenses, primarily employee medical expenses.
- Depreciation and Amortization increased $74 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 $37 million primarily due to the 2008 favorable effect of interest income related to federal income tax refunds filed with the IRS and the second quarter 2009 recognition of other-than-temporary losses related to equity investments held by EIS.
- Carrying Costs Income decreased $31 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 $27 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance 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 $29 million primarily due to increased long-term debt.
- Income Tax Expense increased $25 million primarily due to an increase in pretax book income.

AEP River Operations

Third Quarter of 2009 Compared to Third Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $11 million in 2008 to $10 million in 2009 primarily due to lower revenues as a result of a weak import market.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment increased from $21 million in 2008 to $22 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 as a result of a weak import market.

Generation and Marketing

Third Quarter of 2009 Compared to Third Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $16 million in 2008 to $5 million in 2009 primarily due to lower gross margins at the Oklaunion Plant as a result of lower power prices in ERCOT.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $43 million in 2008 to $33 million in 2009 primarily due to lower gross margins at the Oklaunion Plant as a result of lower power prices in ERCOT.

All Other

Third Quarter of 2009 Compared to Third Quarter of 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from a loss of $10 million in 2008 to a loss of $17 million in 2009.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $133 million in 2008 to a loss of $45 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. 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 $16 million in the third quarter of 2009 compared to the third quarter of 2008 primarily due to an increase in pretax book income, partially offset by state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Income Tax Expense decreased $73 million in the nine-month period ended September 30, 2009 compared to the nine-month period ended September 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

	September 30, 2009		December 31, 2008	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 17,253	56.2%	$ 15,983	55.6%
Short-term Debt	352	1.1	1,976	6.9
Total Debt	17,605	57.3	17,959	62.5
Preferred Stock of Subsidiaries	61	0.2	61	0.2
AEP Common Equity	13,064	42.5	10,693	37.2
Noncontrolling Interests	-	-	17	0.1

Total Debt and Equity Capitalization	$	30,730	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 believe we have adequate liquidity under our existing credit facilities. At September 30, 2009, we had $3.6 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. 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

The financial markets were volatile at both a global and domestic level during the last quarter of 2008 and first half of 2009. We issued $1.9 billion of long-term debt in the first nine months of 2009 and $1.64 billion (net proceeds) of AEP common stock in April 2009. These actions 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. In September 2009, OPCo issued $500 million of 5.375% senior unsecured notes which may be used to pay at maturity some of its outstanding debt due in 2010. We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At September 30, 2009, our available liquidity was approximately $3.6 billion as illustrated in the table below:

		Amount (in millions)		Maturity
Commercial Paper Backup:				
Revolving Credit Facility	$	1,500		March 2011
Revolving Credit Facility		1,454	(a)	April 2012
Revolving Credit Facility		627	(a)	April 2011
Total		3,581		
Cash and Cash Equivalents		877		
Total Liquidity Sources		4,458		
Less: AEP Commercial Paper Outstanding		347		
Letters of Credit Issued		470		
Net Available Liquidity	$	3,641		

(a) Net of contractually terminated Lehman Brothers Bank's commitment amount of $69 million.

As of September 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 a $627 million credit facility which can be utilized for letters of credit or draws. 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 commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. In 2009, we repaid the $2 billion borrowed under the credit facilities during 2008 primarily with proceeds from our equity offering. The maximum amount of commercial paper outstanding during 2009 was $614 million. The weighted-average interest rate for our commercial paper during 2009 was 0.63%.

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. The previous sale of receivables agreement provided a commitment of $700 million.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At September 30, 2009, this contractually-defined percentage was 53.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. At September 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 in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

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 September 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 398 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in October 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 September 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.
- Affirmed the Baa2 rating for TCC and downgraded TNC to Baa2. Both companies were also placed on stable outlook.
- 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.
- Downgraded OPCo to Baa1 and placed it on stable outlook.

In 2009, Fitch:

- Affirmed its stable rating outlook for I&M, PSO and TNC.
- Changed its rating outlook for SWEPCo and TCC from stable to negative.
- Downgraded APCo's senior unsecured rating to BBB and placed it on stable outlook.

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.

	Nine Months Ended September 30,	
	2009	2008
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 411	$ 178
Net Cash Flows from Operating Activities	1,871	2,059
Net Cash Flows Used for Investing Activities	(2,097)	(3,061)
Net Cash Flows from Financing Activities	692	1,162
Net Increase in Cash and Cash Equivalents	466	160
Cash and Cash Equivalents at End of Period	$ 877	$ 338

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

Nine Months Ended
September 30,

	2009	2008
	(in millions)	
Net Income	$ 1,126	$ 1,234
Less: Discontinued Operations, Net of Tax	-	(1)
Income Before Discontinued Operations	1,126	1,233
Depreciation and Amortization	1,200	1,123
Other	(455)	(297)
Net Cash Flows from Operating Activities	$ 1,871	$ 2,059

Net Cash Flows from Operating Activities decreased in 2009 primarily due to a decline in net income and an increase in fuel inventory which should be recoverable through future fuel rates as the inventory is consumed.

Net Cash Flows from Operating Activities were $1.9 billion in 2009 consisting primarily of Net Income of $1.1 billion and $1.2 billion 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 unfavorable weather conditions and an increase in under-recovered fuel primarily in Ohio and West Virginia.

Net Cash Flows from Operating Activities were $2.1 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.2 billion and $1.1 billion 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 coal and natural gas prices.

Investing Activities

	Nine Months Ended September 30,	
	2009	2008
	(in millions)	
Construction Expenditures	$ (2,123)	$ (2,576)
Purchases/Sales of Investment Securities, Net	(49)	(474)
Acquisitions of Nuclear Fuel	(153)	(99)
Acquisitions of Assets	(70)	(97)
Proceeds from Sales of Assets	258	83
Other	40	102
Net Cash Flows Used for Investing Activities	$ (2,097)	$ (3,061)

Net Cash Flows Used for Investing Activities were $2.1 billion in 2009 and $3.1 billion in 2008 and primarily relate 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 as planned and $95 million for sales of transmission assets in Texas to ETT based upon the original partner agreement.

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 captive insurance company.

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions)	
Issuance of Common Stock, Net	$ 1,706	$ 106
Issuance/Retirement of Debt, Net	(371)	1,621
Dividends Paid on Common Stock	(564)	(500)
Other	(79)	(65)
Net Cash Flows from Financing Activities	$ 692	$ 1,162

Net Cash Flows from Financing Activities in 2009 were $692 million. Issuance of Common Stock, Net of $1.7 billion is comprised of 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 $371 million. These retirements included a repayment of $2 billion outstanding under our credit facilities primarily from the proceeds of our common stock issuance and issuances of $1.6 billion of senior unsecured and debt notes and $327 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 $1.2 billion. Our net debt issuances were $1.6 billion. These issuances included net increases of $1.3 billion in senior unsecured notes, $642 million of short-term debt and $315 million of junior subordinated debentures. These net increases in outstanding debt were partially offset by a net reacquisition of $370 million of pollution control bonds and retirements of $53 million of mortgage notes and $125 million of securitization bonds.

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:

	September 30, 2009	December 31, 2008
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ 530	$ 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 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 that established standard service offer rates. The ESPs will be in effect through 2011. The ESP order authorized revenue increases during the ESP period and capped the overall revenue increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 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 avoid having the resultant rate increases exceed 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 three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. The FAC deferrals at September 30, 2009 were $36 million and $238 million for CSPCo and OPCo, respectively, inclusive of carrying charges at the weighted average cost of capital.

In August 2009, an intervenor filed for rehearing requesting, among other things, that the PUCO order CSPCo and OPCo to cease and desist from charging ESP rates, to revert to the rate stabilization plan rates and to compel a refund, including interest, of the amounts collected by CSPCo and OPCo. CSPCo and OPCo filed a response stating the rates being charged by CSPCo and OPCo have been authorized by the PUCO and there was no basis for precluding CSPCo and OPCo from continuing to charge those rates. In September 2009, certain intervenors filed appeals of the March 2009 order and the July 2009 rehearing entry with the Supreme Court of Ohio. One of the intervenors, the Ohio Consumers’ Counsel, has asked the court to stay, pending the outcome of its appeal, a portion of the authorized ESP rates which the Ohio Consumers’ Counsel characterizes as being retroactive. In October 2009, the Supreme Court of Ohio denied the Ohio Consumers' Counsel's request for a stay and granted motions to dismiss both appeals.

In September 2009, CSPCo and OPCo filed their initial quarterly FAC filing with the PUCO. An order approving the FAC 2009 filings will not be issued until a financial audit and prudency review is performed by independent third parties and reviewed by the PUCO.

In October 2009, the PUCO convened a workshop to begin to determine the methodology for the Significantly Excessive Earnings Test (SEET). The SEET requires the PUCO to determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. This will be determined by measuring whether the utility’s earned return on common equity 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 ESP order, the PUCO determined that off-system sales margins and FAC deferral phase-in credits should be excluded from the SEET methodology. However, 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 excess amount would 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 the workshop is completed, the PUCO issues SEET guidelines, a SEET filing is made by CSPCo and OPCo in 2010 and the PUCO issues an order thereon. The SEET workshop will also determine whether CSPCo’s and OPCo’s earnings will be measured on an individual company basis or on a combined CSPCo/OPCo basis.

In October 2009, an intervenor filed a complaint for writ of prohibition with the Supreme Court of Ohio requesting the Court to prohibit CSPCo and OPCo from billing and collecting any ESP rate increases that the PUCO authorized as the intervenor believes the PUCO's statutory jurisdiction over CSPCo's and OPCo's ESP application ended on December 28, 2008, which was 150 days after the filing of the ESP applications. CSPCo and OPCo plan on filing a response in opposition to the complaint for writ of prohibition.

Management is unable to predict the outcome of the various ongoing proceedings and litigation discussed above including the SEET, the FAC filing review and the various appeals to the Supreme Court of Ohio relating to the ESP order. If these proceedings result in adverse rulings, it could have an adverse effect on future net income and cash flows.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, 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. I&M is repairing Unit 1 to resume operations as early as the fourth quarter of 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 September 30, 2009, we recorded $122 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. Through September 30, 2009, I&M received partial payments of $72 million 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 $145 million in revenues and applied $59 million of the accidental outage insurance proceeds to reduce customer bills.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. 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 flows were 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

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(d)	$ 199(d)	Gas	Combined-cycle	580	2013
SWEPCo	Stall		Louisiana	386	364	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(e)	Arkansas	1,633(e)	622(f)	Coal	Ultra-supercritical	600(e)	2012
APCo	Mountaineer	(g)		(g)		Coal	IGCC	629	(g)

CSPCo/OPCo	Great Bend (g)	West Virginia Ohio	(g)	Coal	IGCC	629	(g)

(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) During 2009, AEGCo suspended construction of the Dresden Plant. As a result, AEGCo has stopped recording AFUDC and will resume recording AFUDC once construction is resumed.
(e) SWEPCo owns approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. See "Turk Plant" section below.
(f) Amount represents SWEPCo's CWIP balance only.
(g) Construction of IGCC plants is subject to regulatory approvals.

Turk Plant

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 grant the CECPN 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 Turk 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. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals' decision. While the appeal is pending, SWEPCo is continuing construction of the Turk Plant.

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 appeals by the APSC and SWEPCo 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 CO2 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. 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. If the cost cap restrictions are upheld and construction or CO2 emission costs exceed the restrictions or if the intervenor appeal is successful, it could have an adverse effect on net income, cash flows and possibly financial condition.

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 of the air permit approval 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 air 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. The petition will be acted on by December 2009 according to the terms of a recent settlement between the petitioners and the Federal EPA. The Turk Plant cannot be placed into service without an air permit. In August 2009, these same parties filed a petition with the APCEC to halt construction of the Turk Plant. In September 2009, the APCEC voted to allow construction of the Turk Plant to continue and rejected the request for a stay. If the air permit were to be remanded or ultimately revoked, construction of the Turk Plant would be suspended or cancelled.

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 September 30, 2009, and excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $646 million of expenditures (including AFUDC and capitalized interest and related transmission costs of $24 million) and has contractual construction commitments for an additional $515 million (including related transmission costs of $1 million). As of September 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.

PSO Purchase Power Agreement

As a result of the 2008 Request for Proposals following a December 2007 OCC order that found PSO had a need for new base load generation by 2012, PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, executed a long-term purchase power agreement (PPA). The PPA is for the annual purchase of approximately 520 MW of electric generation from the 795 MW natural gas-fired generating plant in Jenks, Oklahoma for a term of approximately ten years beginning in June 2012. In May 2009, an application seeking approval was filed with the OCC. 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. In August 2009, a settlement agreement was filed with the OCC. In September 2009, the OCC approved the settlement agreement including the recovery of these purchased power costs through a separate base load purchased power rider.

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.

In August 2009, AEP applied with the U.S. Department of Energy (DOE) for $566 million in federal stimulus money for gridSMART, clean coal technology and hydro generation projects. If granted, the funds will provide capital and reduce the amount of money sought from customers. Management is unable to predict the likelihood of the DOE granting the federal stimulus money to AEP or the timing of the DOE's decision. The requested federal stimulus money is proposed for the following projects:

Company	Proposed Project	Federal Stimulus Funds Requested (in millions)		
APCo	Carbon Capture and Sequestration Demonstration Project at the Mountaineer Plant	$	334	
APCo	Hydro Generation Modernization Project in London, W.V.		2	
CSPCo	gridSMART		75	
TCC	gridSMART		123	(a)
TNC	gridSMART		32	(a)
ETT	gridSMART		12	

(a) In October 2009, these applications were not selected by the DOE for award.

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 SO2, NOx, particulate matter and mercury from fossil fuel-fired power plants; and
- Requirements under the Clean Water Act 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 CO2 and other 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 CO2 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 (CCS) program funded through rates to accelerate the development of this technology as well as significant funding through bonus allowances provided to CCS 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 and the Senate released draft cap and trade legislation on September 30. 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 CO2 and other gases under existing laws. In September 2009, the Federal EPA issued a final mandatory GHG reporting rule covering a broad range of facilities emitting in excess of 25,000 tons of GHG emissions per year. The Federal EPA has also issued proposed light duty vehicle GHG emissions standards for model years 2012-2016, and a proposed scheme to streamline and phase in regulation of stationary source GHG emissions through the NSR's prevention of significant deterioration and CAA's Title V permitting programs. The Federal EPA stated its intent to finalize the vehicle standards and permitting rule in conjunction with or following a final endangerment finding, and is reconsidering whether to include GHG emissions in a number of stationary source standards, including standards that apply to electric utility units. Some of the policy approaches being discussed by the Federal EPA 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 and that reasonable and comprehensive legislative action is preferable. Even if reasonable CO2 and other GHG emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. Management believes that costs of complying with new CO2 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.

Proposed Health Care Legislation

The U.S. Congress, supported by President Obama, is debating health care reform that could have a significant impact on our benefits and costs. The discussion centers around universal coverage, revenue sources to keep it deficit neutral and changes to Medicare that could significantly impact our employees and retirees and the benefits and costs of our benefit plans. Until legislation is final, the impact is impossible to predict.

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. SFAS 141R is included in the "Business Combinations" accounting guidance.

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. SFAS 160 is included in the "Consolidation" accounting guidance.

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. SFAS 161 is included in the "Derivatives and Hedging" accounting guidance.

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. SFAS 165 is included in the "Subsequent Events" accounting guidance.

The FASB issued SFAS 168 "The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles" (SFAS 168) establishing the FASB Accounting Standards CodificationTM as the authoritative source of accounting principles for preparation of financial statements and reporting in conformity with GAAP by nongovernmental entities. We adopted SFAS 168 effective third quarter of 2009. It required an update of all references to authoritative accounting literature. SFAS 168 is included in the "Generally Accepted Accounting Principles" accounting guidance.

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. EITF 08-5 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

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. EITF 08-6 is included in the "Investments – Equity Method and Joint Ventures" accounting guidance.

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. EITF 03-6-1 is included in the "Earnings Per Share" accounting guidance.

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. FSP SFAS 107-1 and APB 28-1 is included in the "Financial Instruments" accounting guidance.

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. FSP SFAS 115-2 and SFAS 124-2 is included in the "Investments – Debt and Equity Securities" accounting guidance.

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. SFAS 142-3 is included in the "Intangibles – Goodwill and Other" accounting guidance.

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. SFAS 157-2 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

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. FSP SFAS 157-4 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

Pronouncements Effective in the Future

The FASB issued ASU 2009-05 "Measuring Liabilities at Fair Value" (ASU 2009-05) updating the "Fair Value Measurement and Disclosures" accounting guidance. The guidance specifies the valuation techniques that should be used to fair value a liability in the absence of a quoted price in an active market. The new accounting guidance is effective for interim and annual periods beginning after the issuance date. Although we have not completed our analysis, we do not expect this update to have a material impact on our financial statements. We will adopt ASU 2009-05 effective fourth quarter of 2009.

The FASB issued ASU 2009-12 “Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)” (ASU 2009-12) updating the “Fair Value Measurement and Disclosures” accounting guidance for the fair value measurement of investments in certain entities that calculate net asset value per share (or its equivalent). The guidance permits a reporting entity to measure the fair value of an investment within its scope on the basis of the net asset value per share of the investment (or its equivalent). The new accounting guidance is effective for interim and annual periods ending after December 15, 2009. Although we have not completed our analysis, we do not expect this update to have a material impact on our financial statements. We will adopt ASU 2009-12 effective fourth quarter of 2009.

The FASB issued ASU 2009-13 “Multiple-Deliverable Revenue Arrangements” (ASU 2009-13) updating the “Revenue Recognition” accounting guidance by providing criteria for separating consideration in multiple-deliverable arrangements. It establishes a selling price hierarchy for determining the price of a deliverable and expands the disclosures related to a vendor’s multiple-deliverable revenue arrangements. The new accounting guidance is effective prospectively for arrangements entered into or materially modified in years beginning after June 15, 2010. Although we have not completed our analysis, we do not expect this update to have a material impact on our financial statements. We will adopt ASU 2009-13 effective January 1, 2011.

The FASB issued SFAS 166 “Accounting for Transfers of Financial Assets” (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. We continue to review the impact of this standard. We will adopt SFAS 166 effective January 1, 2010. SFAS 166 is included in the “Transfers and Servicing” accounting guidance.

The FASB issued SFAS 167 “Amendments to FASB Interpretation No. 46(R)” (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 may 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 167 is included in the “Consolidation” accounting guidance.

The FASB issued FSP SFAS 132R-1 “Employers’ Disclosures about Postretirement Benefit Plan Assets” (FSP SFAS 132R-1) providing additional disclosure guidance for pension and OPEB plan assets. 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. We expect this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report. FSP SFAS 132R-1 is included in the “Compensation – Retirement Benefits” accounting guidance.

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 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 September 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
September 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	$252	$36	$12	$ 300	$15	$(15)	$300
Noncurrent Assets	178	210	3	391	2	(14)	379

Total Assets	430	246	15	691	17	(29)	679
Current Liabilities	126	23	17	166	18	(48)	136
Noncurrent Liabilities	112	79	1	192	10	(52)	150
Total Liabilities	238	102	18	358	28	(100)	286
Total MTMDerivative Contract Net Assets (Liabilities)	$192	$144	$(3)	$ 333	$(11)	$71	$393

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 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	(77)	(5)	4	(78)
Fair Value of New Contracts at Inception When Entered During the Period (a)	14	61	-	75
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)	9	(16)	-	(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	71	-	-	71
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2009	$192	$144	$(3)	333
Cash Flow Hedge Contracts				(11)
Collateral Deposits				71
Total MTM Derivative Contract Net Assets at September 30, 2009				$393

(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 or (require) cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
September 30, 2009
(in millions)

	Remainder 2009	2010	2011	2012	2013	After 2013 (f)	Total
Utility Operations							
Level 1 (a)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ (1)
Level 2 (b)	24	43	18	3	8	1	97
Level 3 (c)	19	39	6	3	-	-	67
Total	42	82	24	6	8	1	163
Generation and Marketing							
Level 1 (a)	(2)	1	-	-	-	-	(1)
Level 2 (b)	1	14	17	16	19	41	108
Level 3 (c)	-	1	1	2	3	30	37
Total	(1)	16	18	18	22	71	144
All Other							
Level 1 (a)	-	-	-	-	-	-	-
Level 2 (b)	(1)	(4)	2	-	-	-	(3)
Level 3 (c)	-	-	-	-	-	-	-
Total	(1)	(4)	2	-	-	-	(3)
Total							
Level 1 (a)	(3)	1	-	-	-	-	(2)
Level 2 (b)	24	53	37	19	27	42	202
Level 3 (c) (d)	19	40	7	5	3	30	104
Total	40	94	44	24	30	72	304
Dedesignated Risk Management Contracts (e)	4	14	6	5	-	-	29
Total MTM Risk Management Contract Net Assets	$ 44	$ 108	$ 50	$ 29	$ 30	$ 72	$ 333

(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 the accounting guidance for "Derivatives and Hedging." 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 $72 million in individual periods beyond 2013. $51 million of this mark-to-market value is in periods 2014-2018, $14 million is in periods 2019-2023 and $7 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 September 30, 2009, our credit exposure net of collateral to sub investment grade counterparties was approximately 11.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of September 30, 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	$775	$69	$706	2	$ 228
Split Rating	7	-	7	2	7
Noninvestment Grade	4	2	2	2	1
No External Ratings:					
Internal Investment Grade	75	4	71	4	56
Internal Noninvestment Grade	112	12	100	3	86
Total as of September 30, 2009	$973	$87	$886	13	$ 378
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 September 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

Nine Months Ended September 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 September 30, 2009, the estimated EaR on our debt portfolio for the following twelve months was $12 million.

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

	Three Months Ended		Nine Months Ended	
REVENUES	2009	2008	2009	2008
Utility Operations	$3,364	$4,108	$9,666	$10,318
Other Revenues	183	83	541	886
TOTAL REVENUES	3,547	4,191	10,207	11,204
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	931	1,480	2,624	3,513
Purchased Electricity for Resale	247	394	800	1,023
Other Operation and Maintenance	899	1,010	2,724	2,870
Gain on Sales of Assets, Net	(2)	(6)	(13)	(14)
Asset Impairments and Other Related Charges	-	-	-	(255)
Depreciation and Amortization	421	387	1,200	1,123
Taxes Other Than Income Taxes	193	189	582	578
TOTAL EXPENSES	2,689	3,454	7,917	8,838
OPERATING INCOME	858	737	2,290	2,366
Other Income (Expense):				
Interest and Investment Income	5	14	5	45
Carrying Costs Income	12	21	33	64
Allowance for Equity Funds Used During Construction	23	11	59	32
Interest Expense	(248)	(216)	(726)	(669)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	650	567	1,661	1,838
Income Tax Expense	208	192	535	608
Equity Earnings of Unconsolidated Subsidiaries	4	1	5	3
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	446	376	1,131	1,233
DISCONTINUED OPERATIONS, NET OF TAX	-	-	-	1
INCOME BEFORE EXTRAORDINARY LOSS	446	376	1,131	1,234
EXTRAORDINARY LOSS, NET OF TAX	-	-	(5)	-
NET INCOME	446	376	1,126	1,234
Less: Net Income Attributable to Noncontrolling Interests	2	1	5	4

NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	444	375	1,121	1,230
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	1	2	2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$443	$374	$1,119	$1,228
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	476,948,143	402,286,779	452,255,119	401,535,661
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Discontinued Operations and Extraordinary Loss	$0.93	$0.93	$2.48	$3.06
Discontinued Operations, Net of Tax	-	-	-	-
Income Before Extraordinary Loss	0.93	0.93	2.48	3.06
Extraordinary Loss, Net of Tax	-	-	(0.01)	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.93	$0.93	$2.47	$3.06
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	477,111,144	403,910,309	452,495,494	402,925,534
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Discontinued Operations and Extraordinary Loss	$0.93	$0.93	$2.48	$3.05
Discontinued Operations, Net of Tax	-	-	-	-
Income Before Extraordinary Loss	0.93	0.93	2.48	3.05
Extraordinary Loss, Net of Tax	-	-	(0.01)	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.93	$0.93	$2.47	$3.05
CASH DIVIDENDS PAID PER SHARE	$0.41	$0.41	$1.23	$1.23

See Condensed Notes to Condensed consolidated Financial Statements

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

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$877	$411
Other Temporary Investments	259	327
Accounts Receivable:		
Customers	600	569
Accrued Unbilled Revenues	402	449
Miscellaneous	63	90
Allowance for Uncollectible Accounts	(36)	(42)
Total Accounts Receivable	1,029	1,066
Fuel	998	634
Materials and Supplies	569	539
Risk Management Assets	300	256
Regulatory Asset for Under-Recovered Fuel Costs	103	284
Margin Deposits	101	86
Prepayments and Other Current Assets	243	172
TOTAL CURRENT ASSETS	4,479	3,775
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	22,552	21,242
Transmission	8,198	7,938
Distribution	13,336	12,816
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,821	3,741
Construction Work in Progress	3,251	3,973
Total Property, Plant and Equipment	51,158	49,710
Accumulated Depreciation and Amortization	17,337	16,723
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	33,821	32,987
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,360	3,783
Securitized Transition Assets	1,940	2,040
Spent Nuclear Fuel and Decommissioning Trusts	1,364	1,260
Goodwill	76	76
Long-term Risk Management Assets	379	355
Deferred Charges and Other Noncurrent Assets	774	879
TOTAL OTHER NONCURRENT ASSETS	8,893	8,393
TOTAL ASSETS	$47,193	$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
September 30, 2009 and December 31, 2008
(Unaudited)

		2009		2008
CURRENT LIABILITIES		(in millions)		
Accounts Payable	$	1,004	$	1,297
Short-term Debt		352		1,976
Long-term Debt Due Within One Year		1,540		447
Risk Management Liabilities		136		134
Customer Deposits		265		254
Accrued Taxes		470		634
Accrued Interest		232		270
Regulatory Liability for Over-Recovered Fuel Costs		107		66
Other Current Liabilities		881		1,219
TOTAL CURRENT LIABILITIES		4,987		6,297
NONCURRENT LIABILITIES				
Long-term Debt		15,713		15,536
Long-term Risk Management Liabilities		150		170
Deferred Income Taxes		5,824		5,128
Regulatory Liabilities and Deferred Investment Tax Credits		2,901		2,789
Asset Retirement Obligations		1,197		1,154
Employee Benefits and Pension Obligations		2,168		2,184
Deferred Credits and Other Noncurrent Liabilities		1,128		1,126
TOTAL NONCURRENT LIABILITIES		29,081		28,087
TOTAL LIABILITIES		34,068		34,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption		61		61
Commitments and Contingencies (Note 4)				
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
2009 2008				
Shares Authorized 600,000,000 600,000,000				
Shares Issued 497,649,344 426,321,248				
(20,249,992 shares were held in treasury at September 30, 2009 and December 31, 2008)		3,235		2,771
Paid-in Capital		5,826		4,527
Retained Earnings		4,407		3,847
Accumulated Other Comprehensive Income (Loss)		(404)		(452)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		13,064		10,693
Noncontrolling Interests		-		17

TOTAL EQUITY		13,064		10,710
TOTAL LIABILITIES AND EQUITY	$	47,193	$	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 Nine Months Ended September 30, 2009 and 2008
(in millions)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$1,126	$1,234
Less: Discontinued Operations, Net of Tax	-	(1)
Income Before Discontinued Operations	1,126	1,233
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,200	1,123
Deferred Income Taxes	662	397
Extraordinary Loss, Net of Tax	5	-
Carrying Costs Income	(33)	(64)
Allowance for Equity Funds Used During Construction	(59)	(32)
Mark-to-Market of Risk Management Contracts	(99)	14
Amortization of Nuclear Fuel	41	72
Deferred Property Taxes	144	136
Fuel Over/Under-Recovery, Net	(377)	(284)
Gain on Sales of Assets, Net	(13)	(14)
Change in Other Noncurrent Assets	26	(160)
Change in Other Noncurrent Liabilities	164	(74)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	68	(69)
Fuel, Materials and Supplies	(394)	(49)
Margin Deposits	(15)	(20)
Accounts Payable	(29)	77
Customer Deposits	11	(14)
Accrued Taxes, Net	(165)	(40)
Accrued Interest	(38)	(5)
Other Current Assets	(71)	(43)
Other Current Liabilities	(283)	(125)
Net Cash Flows from Operating Activities	1,871	2,059
INVESTING ACTIVITIES		
Construction Expenditures	(2,123)	(2,576)
Change in Other Temporary Investments, Net	72	106
Purchases of Investment Securities	(573)	(1,386)
Sales of Investment Securities	524	912
Acquisitions of Nuclear Fuel	(153)	(99)
Acquisitions of Assets	(70)	(97)
Proceeds from Sales of Assets	258	83
Other Investing Activities	(32)	(4)
Net Cash Flows Used for Investing Activities	(2,097)	(3,061)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	1,706	106

Issuance of Long-term Debt	1,912	2,561
Change in Short-term Debt, Net	(1,624)	642
Retirement of Long-term Debt	(659)	(1,582)
Principal Payments for Capital Lease Obligations	(62)	(76)
Dividends Paid on Common Stock	(564)	(500)
Dividends Paid on Cumulative Preferred Stock	(2)	(2)
Other Financing Activities	(15)	13
Net Cash Flows from Financing Activities	692	1,162
Net Increase in Cash and Cash Equivalents	466	160
Cash and Cash Equivalents at Beginning of Period	411	178
Cash and Cash Equivalents at End of Period	$877	$338
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$744	$657
Net Cash Paid (Received) for Income Taxes	(74)	126
Noncash Acquisitions Under Capital Leases	53	47
Noncash Acquisition of Land/Mineral Rights	-	42
Construction Expenditures Included in Accounts Payable at September 30,	229	373
Acquisition of Nuclear Fuel Included in Accounts Payable at September 30,	-	66

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 Nine Months Ended September 30, 2009 and 2008
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	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	3	17	89				106
Common Stock Dividends				(494)		(6)	(500)
Preferred Stock Dividends				(2)			(2)
Other Changes in Equity			3			1	4
SUBTOTAL – EQUITY							9,694
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $5					(10)		(10)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $5					9		9
NET INCOME				1,230		4	1,234
TOTAL COMPREHENSIVE INCOME							1,240
TOTAL EQUITY – SEPTEMBER 30, 2008	425	$ 2,760	$ 4,444	$ 3,861	$ (148)	$ 17	$ 10,934
TOTAL EQUITY – DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	71	464	1,294				1,758
Common Stock Dividends				(559)		(5)	(564)
Preferred Stock Dividends				(2)			(2)

Purchase of JMG			55			(18)	37
Other Changes in Equity			(50)			1	(49)
SUBTOTAL – EQUITY							11,890
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $3					5		5
Securities Available for Sale, Net of Tax of $5					10		10
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $18					33		33
NET INCOME				1,121		5	1,126
TOTAL COMPREHENSIVE INCOME							1,174
TOTAL EQUITY – SEPTEMBER 30, 2009	497	$ 3,235	$ 5,826	$ 4,407	$ (404)	$ -	$ 13,064

See Condensed Notes to Condensed Consolidated Financial Statements.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed consolidated financial statements and footnotes were prepared in accordance with 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 condensed consolidated 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 nine months ended September 30, 2009 is 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 October 30, 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 Current Report on Form 8-K as filed with the SEC on May 1, 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 September 30,			
	2009		2008	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$443		$374	
Weighted Average Number of Basic Shares Outstanding	476.9	$0.93	402.3	$0.93
Weighted Average Dilutive Effect of:				
Performance Share Units	0.1	-	1.3	-
Stock Options	-	-	0.1	-
Restricted Stock Units	0.1	-	0.1	-
Restricted Shares	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	477.1	$0.93	403.9	$0.93

	Nine Months Ended September 30,			
	2009		2008	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$1,119		$1,228	
Weighted Average Number of Basic Shares Outstanding	452.3	$2.47	401.5	$3.06
Weighted Average Dilutive Effect of:				
Performance Share Units	0.2	-	1.0	(0.01)
Stock Options	-	-	0.2	-

Restricted Stock Units	-	-	0.1	-
Restricted Shares	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	452.5	$2.47	402.9	$3.05

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

Options to purchase 612,916 and 146,900 shares of common stock were outstanding at September 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 average quarter market price of the common shares and, therefore, the effect would be antidilutive.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" 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 the accounting guidance for "Variable Interest Entities." 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 were applied consistently.

We are the primary beneficiary of Sabine, DHLC, JMG, DCC Fuel LLC (DCC Fuel) 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 Sabine, DHLC, DCC Fuel or EIS that was not previously contractually required. Refer to the discussion of JMG below for details regarding payments that were not 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 that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended September 30, 2009 and 2008 were $34 million and $31 million, respectively, and for the nine months ended September 30, 2009 and 2008 were $95 million and $79 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. SWEPCo and Cleco Corporation equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC it receives 100% of the management fee. 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 the three months ended September 30, 2009 and 2008 were $12 million and $11 million, respectively, and for the nine months ended September 30, 2009 and 2008 were $31 million and $32 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 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. Based on the structure of the entity, management has concluded OPCo is the primary beneficiary and is required to consolidate JMG. 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 resulting in an elimination of OPCo's Noncontrolling Interest related to JMG and an increase in Common Shareholder's Equity of $54 million. In August and September 2009, JMG reacquired $218 million of auction rate debt, funded by OPCo capital contributions to JMG. These reacquisitions were not contractually required. JMG is a wholly-owned subsidiary of OPCo with a capital structure of 85% equity, 15% debt.

OPCo intends to cancel the lease and dissolve JMG in December 2009. The assets and liabilities of JMG will remain incorporated with OPCo's business. OPCo's total billings from JMG for the three months ended September 30, 2009 and 2008 were $1 million and $13 million, respectively, and for the nine months ended September 30, 2009 and 2008 were $50 million and $39 million, respectively. See the tables below for the classification of JMG's assets and liabilities on our Condensed Consolidated Balance Sheets.

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 we are required to consolidate the protected cell. Our insurance premium payments to EIS for the three months ended September 30, 2009 and 2008 were $13 million and $11 million, respectively, and for the nine months ended September 30, 2009 and 2008 were $30 million and $28 million, respectively. See the tables below for the classification of EIS's assets and liabilities on our Condensed Consolidated Balance Sheets.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel. DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. DCC Fuel is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the lease will be made semi-annually on April 1 and October 1, beginning in April 2010. As of September 30, 2009, no payments have been made by I&M to DCC Fuel. The lease was recorded as a capital lease on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 month lease term. Based on the structure, management has concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital lease is eliminated upon consolidation. See the tables below for the classification of DCC Fuel'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
September 30, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	I&M DCC Fuel	EIS

ASSETS					
Current Assets	$38	$19	$18	$38	$125
Net Property, Plant and Equipment	133	29	407	101	-
Other Noncurrent Assets	30	10	-	65	2
Total Assets	$201	$58	$425	$204	$127
LIABILITIES AND EQUITY					
Current Liabilities	$27	$15	$20	$38	$38
Noncurrent Liabilities	174	40	46	166	75
Equity	-	3	359	-	14
Total Liabilities and Equity	$201	$58	$425	$204	$127

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

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	I&M DCC Fuel	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 AEP 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. Neither the “Ohio Series” or “Allegheny Series” are considered VIEs. The other series is not considered a VIE. 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. 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:

	September 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	$ 11	$ 11	$ 4	$ 4
Retained Earnings	2	2	2	2
Total Investment in PATH-WV	$ 13	$ 13	$ 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 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 depreciation expense of:

	Total Depreciation Expense Variance	
	Three Months Ended September 30, 2009/2008	Nine Months Ended September 30, 2009/2008
	(in millions)	
CSPCo	$ (4)	$ (13)
OPCo	18	52

The net change in depreciation rates resulted in decreases to our net-of-tax, basic earnings per share of $0.02 and $0.06 for the three months ended September 30, 2009 and nine months ended September 30, 2009, respectively.

Supplementary Information

	Three Months Ended	Nine Months Ended

Related Party Transactions	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
	(in millions)			
AEP Consolidated Revenues – Utility Operations:				
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% owned) (a)	$-	$(14)	$-	$(40)
AEP Consolidated Revenues – Other:				
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	7	7	22	21
AEP Consolidated Expenses – Purchased Energy for Resale:				
Ohio Valley Electric Corporation (43.47% Owned)	71	70	213	194

(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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions)			
Income Before Discontinued Operations and Extraordinary Loss	$443	$374	$1,124	$1,227
Discontinued Operations, Net of Tax	-	-	-	1
Extraordinary Loss, Net of Tax	-	-	(5)	-
Net Income	$443	$374	$1,119	$1,228

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 nine 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 141R is included in the "Business Combinations" accounting guidance.

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. SFAS 160 is included in the "Consolidation" accounting guidance. The retrospective application of this standard:

- Reclassifies Minority Interest Expense of $1 million and $3 million and Interest Expense of $0 million and $1 million for the three and nine months ended September 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 $1 million and $2 million for the three and nine months ended September 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 Interests in Total Equity on our Condensed Consolidated Balance Sheets.
- Separately reflects changes in Noncontrolling Interests on the Condensed Consolidated Statements of Changes in Equity and Comprehensive Income (Loss).
- Reclassifies dividends paid to noncontrolling interests of $6 million for the nine months ended September 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 161 is included in the "Derivatives and Hedging" accounting guidance.

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. SFAS 165 is included in the "Subsequent Events" accounting guidance.

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

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

We adopted SFAS 168 effective third quarter of 2009. It required an update of all references to authoritative accounting literature. SFAS 168 is included in the "Generally Accepted Accounting Principles" accounting guidance.

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 08-5 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

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. EITF 08-6 is included in the "Investments – Equity Method and Joint Ventures" accounting guidance.

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. EITF 03-6-1 is included in the "Earnings Per Share" accounting guidance.

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 107-1 and APB 28-1 is included in the "Financial Instruments" accounting guidance.

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 115-2 and SFAS 124-2 is included in the "Investments – Debt and Equity Securities" accounting guidance.

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. SFAS 142-3 is included in the "Intangibles – Goodwill and Other" accounting guidance.

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 nine months of 2009. SFAS 157-2 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

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. FSP SFAS 157-4 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

Pronouncements Effective in the Future

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

ASU 2009-05 "Measuring Liabilities at Fair Value" (ASU 2009-05)

In August 2009, the FASB issued ASU 2009-05 updating the "Fair Value Measurement and Disclosures" accounting guidance. The guidance specifies the valuation techniques that should be used to fair value a liability in the absence of a quoted price in an active market.

The new accounting guidance is effective for interim and annual periods beginning after the issuance date. Although we have not completed our analysis, we do not expect this update to have a material impact on our financial statements. We will adopt ASU 2009-05 effective fourth quarter of 2009.

ASU 2009-12 "Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)" (ASU 2009-12)

In September 2009, the FASB issued ASU 2009-12 updating the "Fair Value Measurement and Disclosures" accounting guidance for the fair value measurement of investments in certain entities that calculate net asset value per share (or its equivalent). The guidance permits a reporting entity to measure the fair value of an investment within its scope on the basis of the net asset value per share of the investment (or its equivalent).

The new accounting guidance is effective for interim and annual periods ending after December 15, 2009. Although we have not completed our analysis, we do not expect this update to have a material impact on our financial statements. We will adopt ASU 2009-12 effective fourth quarter of 2009.

ASU 2009-13 "Multiple-Deliverable Revenue Arrangements" (ASU 2009-13)

In October 2009, the FASB issued ASU 2009-13 updating the "Revenue Recognition" accounting guidance by providing criteria for separating consideration in multiple-deliverable arrangements. It establishes a selling price hierarchy for determining the price of a deliverable and expands the disclosures related to a vendor's multiple-deliverable revenue arrangements.

The new accounting guidance is effective prospectively for arrangements entered into or materially modified in years beginning after June 15, 2010. Although we have not completed our analysis, we do not expect this update to have a material impact on our financial statements. We will adopt ASU 2009-13 effective January 1, 2011.

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. We continue to review the impact of this standard. We will adopt SFAS 166 effective January 1, 2010. SFAS 166 is included in the "Transfers and Servicing" accounting guidance.

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 may 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 167 is included in the "Consolidation" accounting guidance.

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. FSP SFAS 132R-1 is included in the "Compensation – Retirement Benefits" accounting guidance.

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 re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a switch to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance 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 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 that established standard service offer rates. The ESPs will be in effect through 2011. The ESP order authorized revenue increases during the ESP period and capped the overall revenue increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 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 avoid having the resultant rate increases exceed 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 three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

The FAC deferrals at September 30, 2009 were $36 million and $238 million for CSPCo and OPCo, respectively, inclusive of carrying charges at the weighted average cost of capital. In the July 2009 rehearing order, the PUCO once again 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's July 2009 rehearing entry 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 PUCO also addressed several additional matters in the ESP order, 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 funds under the American Recovery and Reinvestment Act of 2009. As a result, a rider was established to recover $32 million related to gridSMART during the three-year ESP period. In August 2009, CSPCo filed for $75 million in federal grant funding under the American Recovery and Reinvestment Act of 2009.

- 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 September 30, 2009, CSPCo's and OPCo's remaining liability balances were $6 million each.

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 a response noting 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.

In August 2009, an intervenor filed for rehearing requesting, among other things, that the PUCO order CSPCo and OPCo to cease and desist from charging ESP rates, to revert to the rate stabilization plan rates and to compel a refund, including interest, of the amounts collected by CSPCo and OPCo. CSPCo and OPCo filed a response stating the rates being charged by CSPCo and OPCo have been authorized by the PUCO and there was no basis for precluding CSPCo and OPCo from continuing to charge those rates. In September 2009, certain intervenors filed appeals of the March

2009 order and the July 2009 rehearing entry with the Supreme Court of Ohio. One of the intervenors, the Ohio Consumers' Counsel, has asked the court to stay, pending the outcome of its appeal, a portion of the authorized ESP rates which the Ohio Consumers' Counsel characterizes as being retroactive. In October 2009, the Supreme Court of Ohio denied the Ohio Consumers' Counsel's request for a stay and granted motions to dismiss both appeals.

In September 2009, CSPCo and OPCo filed their initial quarterly FAC filing with the PUCO. An order approving the FAC 2009 filings will not be issued until a financial audit and prudency review is performed by independent third parties and reviewed by the PUCO.

In October 2009, the PUCO convened a workshop to begin to determine the methodology for the Significantly Excessive Earnings Test (SEET). The SEET requires the PUCO to determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. This will be determined by measuring whether the utility's earned return on common equity 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 ESP order, the PUCO determined that off-system sales margins and FAC deferral phase-in credits should be excluded from the SEET methodology. However, 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 excess amount would 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 the workshop is completed, the PUCO issues SEET guidelines, a SEET filing is made by CSPCo and OPCo in 2010 and the PUCO issues an order thereon. The SEET workshop will also determine whether CSPCo's and OPCo's earnings will be measured on an individual company basis or on a combined CSPCo/OPCo basis.

In October 2009, an intervenor filed a complaint for writ of prohibition with the Supreme Court of Ohio requesting the Court to prohibit CSPCo and OPCo from billing and collecting any ESP rate increases that the PUCO authorized as the intervenor believes the PUCO's statutory jurisdiction over CSPCo's and OPCo's ESP application ended on December 28, 2008, which was 150 days after the filing of the ESP applications. CSPCo and OPCo plan on filing a response in opposition to the complaint for writ of prohibition.

Management is unable to predict the outcome of the various ongoing proceedings and litigation discussed above including the SEET, the FAC filing review and the various appeals to the Supreme Court of Ohio relating to the ESP order. If these proceedings result in adverse rulings, it could have an adverse effect on future net income and cash flows.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. 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 jurisdictions 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 response 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 required CSPCo and OPCo to 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.

In September 2009, an intervenor filed a motion with the PUCO requesting that CSPCo and OPCo be required to refund all pre-construction cost revenue to Ohio ratepayers with interest or show cause as to why the amount for the proposed IGCC plant should not be immediately refunded based upon the PUCO's June 2006 order. The intervenor contends that the most recent integrated resource plan filed for the AEP East companies' zone does not reflect the construction of an IGCC plant. In October 2009, CSPCo and OPCo filed a response opposing the intervenor's request to refund revenues collected stating that an integrated resource plan is a planning tool and does not prevent CSPCo and OPCo from meeting the PUCO's five-year time limit.

Management continues to pursue the consideration of construction of an IGCC plant in Ohio although CSPCo and OPCo will not start construction of an IGCC plant until the statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, the litigation will have on future net income and cash flows. However, 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.

Ormet

In December 2008, CSPCo, OPCo and Ormet, a large aluminum company currently operating at a reduced load of approximately 330 MW (Ormet operated at an approximate 500 MW load in 2008), filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The interim arrangement was effective January 1, 2009 and expired in September 2009 upon the filing of a new PUCO-approved long-term power contract between Ormet and CSPCo/OPCo that was effective prospectively through 2018. 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 new FAC phased-in mechanism that 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 for the differential in the approved market price of $53.03 versus the rate paid by Ormet until the effective date of the 2009-2018 power contract.

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 Ormet FAC under-recovery 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 average rate using $38 per MWH for the periods Ormet was in full production and $35 and $34 per MWH at certain curtailed production levels. The $35 and $34 MWH rates are contingent upon Ormet maintaining its employment levels at 900 employees for 2009. The PUCO authorized CSPCo and OPCo to record under-recovery deferrals computed as revenue foregone (the difference between CSPCo's and OPCo's ESP tariff rates 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 reduction for Ormet that declines over time to zero in 2018 and a maximum amount of under-recovery deferrals that ratepayers will be expected to pay via a rider in any given year. For 2010 and 2011, the PUCO set the maximum rate discount at $60 million and the maximum amount of the rate discount other ratepayers should pay at $54 million. To the extent the under-recovery deferrals exceed 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 reduction will be lowered. The new long-term power contract became effective in September 2009 at which point CSPCo and OPCo began deferring as a regulatory asset the unrecovered amounts less Provider of Last Resort (POLR) charges. Rehearing applications filed by CSPCo, OPCo and intervenors were granted by the PUCO. In September 2009 on rehearing, the PUCO ordered that CSPCo and OPCo must credit all Ormet related POLR charges against the under-recovery amounts that CSPCo and OPCo would otherwise recover. As of September 30, 2009, CSPCo and OPCo had $32 million and $34 million, respectively, deferred as regulatory assets related to Ormet under-recovery, which is included in CSPCo's and OPCo's FAC phase-in deferral balance.

Ormet indicated it will operate at reduced operations at least through the end of 2009. Management cannot predict Ormet's on-going electric consumption levels, the resultant prices Ormet will pay and/or the amount that CSPCo and OPCo will defer for future recovery from other customers. If CSPCo and OPCo are not ultimately permitted to recover their under-recovery deferrals, it would have an adverse effect on future net income and cash flows.

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 filings. At September 30, 2009, CSPCo and OPCo have accrued for future recovery regulatory assets of $18 million and $10 million, respectively, including the approved long-term debt only carrying costs. If CSPCo and OPCo are not ultimately permitted to recover their storm damage deferrals, it would have an adverse effect on future net income and cash flows.

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 flows were 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. A decision is not expected from the Texas Supreme Court until 2010.

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 Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) tax benefits to customers. Subsequent to the PUCT's ordered reduction to TCC's securitized stranded costs for 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 ADITC and 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 these 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 $11 million higher for the period July 2008 through September 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 September 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 this 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 re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction in the second quarter of 2009. Management believes that a switch to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance 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 September year to date 2009 net income by approximately $8 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 net catastrophe reserve regulatory asset account as of September 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 increase in the funding level to request both recovery of the then existing regulatory asset balance and to adequately fund a reserve for future storms in a reasonable time period.

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.

2007 Texas Base Rate Increase Appeal

In November 2006, TCC filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rates 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 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. The order increased TCC's annual pretax income by approximately $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.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a base rate case with the PUCT to increase non-fuel base rates by approximately $75 million annually based on a requested return on common equity of 11.5%. The filing includes a base rate increase of $27 million, a vegetation management rider for $16 million and financing cost riders of $32 million related to the construction of the Stall Unit and Turk Plant. In addition, the net merger savings credit of $7 million will be removed from rates and depreciation expense is proposed to decrease by $17 million. The proposed filing would increase SWEPCo's annual pretax income by approximately $51 million.

The proposed Stall Unit rider would recover a return on the Stall Unit investment while the Stall Unit is under construction and continuing after it is placed in service plus recovery of depreciation when it is placed in service in 2010. The proposed Turk Plant rider would recover a return on the Turk Plant investment and will continue until such time that the Turk Plant is included in base rates. Both riders would terminate when base rates are increased to include recovery of the Turk Plant's and the Stall Unit's respective plant investments, plus a return thereon, and a recovery of their related operating expenses. Management is unable to predict the outcome of this filing.

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. In September 2009, ETT filed an application with the PUCT for a CCN under the new law for the purpose of confirming its authority to operate as a transmission-only utility regardless of the outcome of the pending litigation. The parties to the litigation pending at the Texas Court of Appeals have stipulated agreement or indicated they are not opposed to ETT’s request.

During 2009, TCC and TNC sold $93 million and $1 million, respectively, of additional transmission facilities to ETT. As of September 30, 2009, AEP’s net investment in ETT was $47 million. Depending upon ETT’s filing under the new law, 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 September 30, 2009, ETT’s net investment in property, plant and equipment was $236 million, of which $100 million was under construction.

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.

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 October 2009, ETT, TCC and TNC filed joint applications with the PUCT for approval to transfer from TCC and TNC to ETT approximately $69 million and $72 million, respectively, of transmission assets and CWIP. The transfers are planned to be completed by the end of the first quarter of 2010. A decision from the PUCT is pending.

Stall Unit

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

Turk Plant

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

Virginia Rate Matters

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 an application, in May 2009, to recover $102 million of unrecovered 2008 incremental deferred E&R costs plus its 2008 equity costs based on a 12.5% return on equity on its E&R capital investments. However, APCo deferred and recognized income under the E&R legislation based on a return on equity of 10.1%, which was the Virginia SCC staff's recommendation in the prior E&R case. In October 2009, a stipulation agreement was reached between the parties and filed with the Virginia SCC addressing all matters other than rate design and customer class allocation issues. The stipulation agreement allows APCo to recover Virginia incremental E&R costs of $90 million, representing costs deferred during 2008 plus unrecognized 2008 equity costs, using a 10.6% return on equity for collection in 2010. This will result in an immaterial adjustment which will be recorded in the fourth quarter of 2009. The Virginia SCC is expected to approve the stipulation agreement in the fourth quarter of 2009.

As of September 30, 2009, APCo had $88 million of deferred Virginia incremental E&R costs excluding $17 million of unrecognized equity carrying costs. The $88 million consists of $6 million of over-recovered costs collected under the 2008 surcharge, $14 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.

Mountaineer Carbon Capture and Storage Project

In January 2008, APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO2 capture demonstration facility. APCo and Alstom will each own part of the CO2 capture facility. APCo will also construct and own the necessary facilities to store the CO2. RWE AG, a German electric power and natural gas public utility, and the Electric Power Research Institute are participating in the project and providing some funding to offset APCo's costs. APCo's estimated cost for its share of the constructed facilities is $74 million. In May 2009, the West Virginia Department of Environmental Protection issued a permit to inject CO2 that requires, among other items, that APCo monitor the wells for at least 20 years following the cessation of CO2 injection. In September 2009, the capture portion of the project was placed into service and in October 2009, APCo started injecting CO2 in underground storage. The injection of CO2 required the recordation of an asset retirement obligation and an offsetting regulatory asset at its estimated net present value of $36 million in October 2009. Through September 30, 2009, APCo incurred $71 million in capitalized project costs which are included in Regulatory Assets.

APCo currently earns a return on the Virginia portion of the capitalized project costs incurred through June 30, 2008, as a result of a 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 increased Virginia jurisdictional share of its CO2 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 CO2 capture demonstration facility in APCo's last Virginia base rate case, APCo is deferring its 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 the first quarter of 2010. 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 required 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. As a result, in July 2009, APCo filed a base rate case with the Virginia SCC requesting an increase in the generation and distribution portions of its 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. In August 2009, APCo filed supplemental schedules and testimony that decreased the requested annual revenue increase to $154 million which reflected a recent Virginia SCC order in an unaffiliated utility's base rate case concerning the appropriate capital structure to be used in the determination of the revenue requirement. The new generation and distribution base rates will become effective, subject to refund, in December 2009.

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 RAC filing requested an initial $94 million annual revenue requirement representing an annual increase of $24 million above the current level embedded in APCo's Virginia base rates. APCo requested to implement the transmission RAC concurrently with the new base rates in December 2009. See the "Virginia Base Rate Filing" section above. In October 2009, the Virginia SCC approved the stipulation agreement providing for an annual incremental revenue increase in transmission rates of $22 million excluding $2 million of reasonable and prudent PJM administrative costs that may be recovered in base rates.

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. APCo also plans to file for approval of a renewable energy RAC before the end of the first quarter of 2010 to recover costs associated with APCo's wind power purchase agreements. In accordance with Virginia law, APCo is deferring any incremental transmission and environmental costs incurred after December 2008 and any renewable energy costs incurred after August 2009 which are not being recovered in current revenues. As of September 30, 2009, APCo has deferred for future recovery $17 million of environmental costs (excluding $3 million of unrecognized equity carrying costs), $14 million of transmission costs and $1 million of renewable energy costs. 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 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 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. In August 2009, the Virginia SCC issued an order which provided for a $130 million fuel revenue increase, effective August 2009. The reduction in revenues from the requested amount recognizes a lower than projected under-recovery balance and a lower level of projected fuel costs to be recovered through the approved fuel factor. Any fuel under-recovery due to the lower level of projected fuel costs should be deferred as a regulatory asset for future recovery under the FAC true-up mechanism and recoverable, if necessary, either in APCo's next fuel factor proceeding for the period September 2010 through August 2011 or through other statutory mechanisms.

APCo's Filings for an IGCC Plant

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

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 to increase the ENEC rates by approximately $442 million for incremental fuel, purchased power, other energy related costs and environmental compliance project costs 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, 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. The proposed modified ENEC mechanism also provides that to the extent the phase-in deferrals exceed the deferred amounts that would have otherwise existed under the traditional ENEC mechanism, the phase-in deferrals are subject to a carrying charge based upon APCo's and WPCo's weighted average cost of capital. As proposed, 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 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 an 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 to the forecasted ENEC costs and reduced the requested increase to $398 million with a proposed first-year increase of $160 million. The intervenors' forecast adjustments would not impact earnings since the ENEC mechanism would continue to true-up to actual costs. 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.

In September 2009, the WVPSC issued an order granting a $355 million increase to be phased in over the next four years with a first-year increase of $124 million. As of September 30, 2009, APCo's ENEC under-recovery balance was $255 million which is included in Regulatory Assets. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 1, 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan. The order disallowed an immaterial amount of deferred ENEC costs which was recognized in

September 2009. It also lowered annual coal cost projections by $27 million and deferred recovery of unrecovered ENEC deferrals related to price increases on certain renegotiated coal contracts. The WVPSC indicated that it would review the prudency of these additional costs in the next ENEC proceeding. As of September 30, 2009, APCo has deferred $13 million of unrecovered coal costs on the renegotiated coal contracts which is included in APCo's $255 million ENEC under-recovery regulatory asset and has an additional $5 million in purchased fuel costs on the renegotiated coal contracts which is recorded in Fuel on the Condensed Consolidated Balance Sheets. Although management believes the portion of its deferred ENEC under-recovery balance attributable to renegotiated coal contracts is probable of recovery, if the WVPSC were to disallow a portion of APCo's and WPCo's deferred ENEC costs including any costs incurred in the future related to the renegotiated coal contracts, it could 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 with the WVPSC. In September 2009, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

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 September 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.

Although management continues to pursue consideration of 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 and Storage Project

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

Kentucky Rate Matters

Kentucky Storm Restoration Expenses

During 2009, KPCo experienced severe storms causing significant customer outages. In August 2009, KPCo filed a petition with the Kentucky Public Service Commission (KPSC) for an order seeking authorization to defer approximately $10 million of incremental storm restoration expense for review and recovery in KPCo's next base rate proceeding. The requested deferral of the previously expensed $10 million is in addition to the annual $2 million of storm-related operation and maintenance expense included in KPCo's current base rates. Management is unable to predict the outcome of this petition. A decision is expected from the KPSC during the fourth quarter of 2009.

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 based on a return on equity of 11.5%. The base rate increase included a $69 million annual reduction in rates due to an approved 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 an agreed to revenue increase of $44 million, which included a $22 million increase in base rates based on an authorized return on equity of 10.5% and a $22 million initial increase in tracker rates for incremental 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 modified and approved the settlement agreement that provides for an annual increase in revenues of $42 million. The $42 million increase included a $19 million increase in base rates, net of the depreciation rate reduction and a $23 million increase in tracker revenue. The IURC order modified the settlement agreement by removing from base rates the recovery of DSM costs, establishing a tracker with an initial zero amount for DSM costs, requiring I&M to collaborate with other affected parties regarding the design and recovery of future I&M DSM programs, adjusting the sharing of off-system sales margins to 50% above $37.5 million which it included in base rates and approving the recovery of $7 million of previously expensed NSR and OPEB costs which favorably affected 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 NOx and mercury from its existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition requested 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. The petition requested 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 can be recovered in the requested rate adjustment mechanism. Through September 30, 2009, I&M incurred $12 million and $12 million in capitalized facilities cost related to the Rockport and Tanners Creek Plants, respectively, which are included in CWIP. Subsequent to the filing of this petition, the Indiana base rate order included recovery of emission allowance costs. Therefore, that portion of the emission allowances cost for the subject facilities will not be recovered 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 deferred under-recovered fuel costs, the shutdown of the Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire and a projection for the future period of fuel costs increases including Unit 1 shutdown replacement power costs. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4. The filing also included an adjustment, beginning coincident with the receipt of accidental outage 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 accidental outage policy. I&M reached an agreement in February 2009 with intervenors, which was approved by the IURC in March 2009, to collect the prior period under-recovery deferral balance 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 also 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 the fourth quarter of 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 deferral balance approved in the March 2009 order plus recovery of an additional $12 million under-recovered deferral balance from the reconciliation period of December 2008 through May 2009.

In August 2009, an intervenor filed testimony proposing that I&M should refund approximately $11 million through the fuel adjustment clause, which is the intervenor's estimate of the Indiana retail jurisdictional portion of the additional fuel cost during the accidental outage insurance policy deductible period, which is the period from the date of the incident in September 2008 to when the insurance proceeds began in December 2008. In August 2009, I&M and intervenors filed a settlement agreement with the IURC that included the recovery of the $12 million under-recovered deferral balance, subject to refund, over twelve months instead of over six months as originally proposed and an agreement to delay all Unit 1 outage issues in this filing until after the unit is returned to service.

Management cannot predict the outcome of the pending proceedings, including the treatment of the outage insurance proceeds, and whether any fuel clause revenues or insurance proceeds will have to be refunded 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 due to the Cook Plant Unit 1 outage with a portion of the accidental insurance proceeds from the Cook Plant Unit 1 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 whether it will have an 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 two issues. The first issue relates to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed the ALJ recommendations that concluded the FERC and not the OCC had jurisdiction over this matter. In August 2008, the OCC filed a complaint with the FERC concerning this allocation of OSS issue. In December 2008, under an adverse FERC ruling, PSO recorded a regulatory liability to return the reallocated OSS to customers. Effective with the March 2009 billing cycle, PSO began refunding the additional reallocated OSS to its customers. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters."

The second issue concerns a 2002 under-recovery of $42 million of PSO 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 the June 2008 appeal by the OIEC of the ALJ recommendations, the OIEC contended that PSO should not have collected the $42 million without specific OCC approval nor collected the $42 million before the OSS allocation issue was resolved. As such, the OIEC contends that the OCC could and should require PSO to refund the $42 million it collected through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending. Although the OSS allocation issue has been resolved at the FERC, if the OCC were to order PSO to make an additional refund for all or a part of the $42 million, it would have an adverse effect on future net income and cash flows.

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 August 2009, a joint stipulation and settlement agreement (settlement) was filed with the OCC requesting the OCC to issue an order accepting the fuel adjustment clause for 2007 and find that PSO's fuel procurement practices, policies and decisions were prudent. In September 2009, the OCC issued a final order approving the settlement.

2008 Oklahoma Base Rate Filing Appeal

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 terminates and PSO recovers 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 provided 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. PSO was given authority to record additional under/over recovery deferrals for future 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 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 of additional revenues 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. In July 2009, the Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. If the Oklahoma Attorney General or the intervenors' appeals are successful, it could have an adverse effect on future net income and cash flows.

Oklahoma Capital Reliability Rider Filing

In August 2009, PSO filed an application with the OCC requesting a Capital Reliability Rider (CRR) to recover depreciation, taxes and return on PSO's net capital investments for generation, transmission and distribution assets that have been placed into service from September 1, 2008 to June 30, 2009. If approved, PSO would increase billings to customers during the first six months of 2010 by $11 million related to the increase in revenue requirement and $9 million related to the lag between the investment cut-off of June 30, 2009 and the date of the rider implementation of January 1, 2010.

In October 2009, all but two of the parties to the CRR filing agreed to a stipulation that was filed with the OCC to collect no more than $30 million of revenues under the CRR on an annual basis beginning January 2010 until PSO's next base rate order. The CRR revenues are subject to refund with interest pending the OCC's audit. The stipulation also provides for an offsetting fuel revenue reduction via a modification to the fuel adjustment factor of Oklahoma jurisdictional customers on an annual basis by $30 million beginning January 2010 and refunds of certain over-recovered fuel balances during the first quarter of 2010. Finally, the stipulation requires that PSO shall file a base rate case no later than July 2010. Management is unable to predict the outcome of this application.

PSO Purchase Power Agreement

As a result of the 2008 Request for Proposals following a December 2007 OCC order that found PSO had a need for new base load generation by 2012, PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, executed a long-term purchase power agreement (PPA). The PPA is for the annual purchase of approximately 520 MW of electric generation from the 795 MW natural gas-fired generating plant in Jenks, Oklahoma for a term of approximately ten years beginning in June 2012. In May 2009, an application seeking approval was filed with the OCC. 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. In August 2009, a settlement agreement was filed with the OCC. In September 2009, the OCC approved the settlement agreement including the recovery of these purchased power costs through a separate base load purchased power rider.

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). SWEPCo requested an increase in its annual Louisiana retail rates of $11 million to be effective in August 2008 in order to earn the approved formula return on common equity of 10.565%. In August 2008, as provided by the FRP, SWEPCo implemented the FRP rates, subject to refund. During 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 settlement parties to prepare a written agreement to be filed with the LPSC.

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. SWEPCo implemented the FRP rate increase as filed in August 2009, subject to refund. In October 2009, consultants for the LPSC objected to certain components of SWEPCo's FRP calculation. The consultants also recommended refunding the SIA through SWEPCo's FRP. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters." SWEPCo will continue to work with the LPSC regarding the issues raised in their objection. SWEPCo believes the rates as filed are in compliance with the FRP methodology previously approved by the LPSC. If the LPSC disagrees with SWEPCo, it could result in material refunds.

Stall Unit

In May 2006, SWEPCo announced plans to build an intermediate load, 500 MW, natural gas-fired, combustion turbine, combined cycle generating unit at its existing Arsenal Hill Plant location in Shreveport, Louisiana to be named the Stall Unit. SWEPCo submitted the appropriate filings to the LPSC, the PUCT, the APSC and the Louisiana Department of Environmental Quality to seek approvals to construct the Stall Unit. The Stall Unit is currently estimated to cost $435 million, including $49 million of AFUDC, and is expected to be in service in mid-2010.

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 March 2007, the PUCT approved SWEPCo's request for a certificate of necessity for the facility based on a prior cost estimate. 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. 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 including AFUDC and excluding related transmission costs.

As of September 30, 2009, SWEPCo has capitalized construction costs of $364 million, including AFUDC, and has contractual construction commitments of an additional $31 million with the total estimated cost to complete the unit at $435 million. If the final cost of the Stall Unit exceeds the $445 million cost cap, it could 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.

Temporary Funding of Financing Costs during Construction

In October 2009, SWEPCo made a filing with the LPSC requesting temporary recovery of financing costs related to the Louisiana jurisdiction portion of the Turk Plant. In the filing, SWEPCo would recover over three years of an estimated $105 million of construction financing costs related to SWEPCo's ongoing Turk generation construction program through its existing Fuel Adjustment Rider. If approved as requested, recovery would start in January 2010 and continue through 2012 when the Turk Plant is scheduled to be placed in service. According to the filing, the amount of financing costs collected during construction would be refunded to customers, including interest at SWEPCo's long-term debt rate, after the Turk Plant is in service. As filed, the refund would occur over a period not to exceed five years. Finally, SWEPCo requested that both the Turk Plant and the Stall Unit be placed in rates via the formula rate plan without regulatory lag. Management cannot predict the outcome of this filing.

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, paid SWEPCo $104 million in the aggregate for their shares of accrued construction costs and began paying their proportional shares of ongoing construction costs. The joint owners are billed monthly for their share of the on-going construction costs exclusive of AFUDC. Through September 30, 2009, the joint owners paid SWEPCo $196 million for their share of the Turk Plant 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 by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). Certain intervenors appealed the APSC's decision to grant the CECPN 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 Turk 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. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals decision. While the appeal is pending, SWEPCo is continuing construction of the Turk Plant.

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 appeals by the APSC and SWEPCo 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 CO2 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. 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. If the cost cap restrictions are upheld and construction or CO2 emission costs exceed the restrictions or if the intervenor appeal is successful, it could have an adverse effect on net income, cash flows and possibly financial condition.

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 of the air permit approval 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 air 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. The petition will be acted on by December 2009, according to the terms of a recent settlement between the petitioners and the Federal EPA. The Turk Plant cannot be placed into service without an air permit. In August 2009, these same parties filed a petition with the APCEC to halt construction of the Turk Plant. In September 2009, the APCEC voted to allow construction of the Turk Plant to continue and rejected the request for a stay. If the air permit were to be remanded or ultimately revoked, construction of the Turk Plant would be suspended or cancelled.

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 September 30, 2009, and excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $646 million of expenditures (including AFUDC and capitalized interest, and related transmission costs of $24 million). As of September 30, 2009, the joint owners and SWEPCo have contractual construction commitments of approximately $515 million (including related transmission costs of $1 million) and, if the plant had been cancelled, 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 September 2009, SWEPCo, the APSC staff and the Arkansas Attorney General entered into a settlement agreement in which the settling parties agreed to an $18 million increase based on a return on equity of 10.25%. In addition, the settlement agreement will decrease depreciation expense by $10 million. The settlement agreement would increase SWEPCo's annual pretax income by approximately $28 million. The settlement agreement also includes a separate rider of approximately $11 million annually that will allow SWEPCo to recover carrying costs, depreciation and operation and maintenance expenses on the Stall Unit once it is placed into service. Until then, SWEPCo will continue to accrue AFUDC on the Stall Unit. The other parties to the case do not oppose the settlement agreement. If the settlement agreement is approved by the APSC, new base rates will become effective for all bills rendered on or after November 25, 2009.

In January 2009, an ice storm struck in northern Arkansas affecting SWEPCo's customers. SWEPCo incurred 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 $4 million (later adjusted to $3 million) of expensed incremental operation and maintenance costs and to address the recovery of these deferred expenses in the pending base rate case. In July 2009, the APSC issued an order approving the deferral request subject to investigation, analysis and audit of the costs. In August 2009, the APSC staff filed testimony that recommended recovery of approximately $1 million per year through amortization of the deferred ice storm costs over three years in base rates. This amount was included in the $18 million base rate increase agreed upon in the settlement agreement. In September 2009, based upon the APSC audit and recommendation, management established a regulatory asset of $3 million for the recovery of the ice storm restoration costs.

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 refund of a portion or all of the 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 September 30, 2009 was $34 million. As of September 30, 2009, there were no in-process settlements.

Management cannot predict the ultimate outcome of future 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 even though other non-affiliated entities transmit power over AEP's lines. 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. In August 2009, the United States Court of Appeals issued an opinion affirming FERC's refusal to implement a regional rate design in PJM.

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, which 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 from their retail customers. 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 and as a result the use of zonal rates would be unfair and discriminatory to AEP's East zone retail customers. 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 wholesale transmission T&O revenues reduction of transmission cost to retail customers. This case is pending before the U.S. Court of Appeals which in August 2009 ruled against AEP in a similar case. See "The FERC PJM Regional Transmission Rate Proceeding" section above.

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 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. In July 2009, consultants for the LPSC issued an audit report of SWEPCo's Louisiana retail fuel adjustment clause. Within this report, the consultants for the LPSC recommended that SWEPCo refund the SIA, including interest, through the fuel adjustment clause. In October 2009, other consultants for the LPSC recommended refunding the SIA through SWEPCo's formula rate plan. See "2009 Formula Rate Filing" section within "Louisiana Rate Matters." 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. The delayed effective date was approved by the FERC in August 2009 when the FERC accepted the new TA for filing. Settlement discussions are in process. Management is unable to predict the effect, if any, it will have on future net income and cash flows due to timing of the implementation by various state regulators of the FERC's new approved TA.

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 for guarantees in accordance with the accounting guidance for "Guarantees." 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 September 30, 2009, the maximum future payments for all the LOCs issued under the two $1.5 billion credit facilities are approximately $98 million with maturities ranging from October 2009 to July 2010.

We have a $627 million 3-year credit agreement. As of September 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), a consolidated variable interest entity. 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 September 30, 2009, SWEPCo has collected approximately $42 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $23 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $17 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs 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 $1.1 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 $439 million and is recorded in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets as of September 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 September 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 $19 million for I&M and $22 million for SWEPCo for the remaining railcars as of September 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. In 2009, the defendants and the plaintiffs filed appeals. 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 (CO2) 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 CO2 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. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO2 and other GHG under the CAA. The Second Circuit requested supplemental briefs addressing the impact of the U.S. Supreme Court's decision on this case.

In September 2009, the Second Circuit Court issued a ruling vacating the dismissal and remanding the case to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate GHG emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities, and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. We believe the actions are without merit and intend to continue to defend against the claims including seeking further review by the Second Circuit and, if necessary, the United States Supreme Court.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that GHG emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government, and that no initial policy determination was required to adjudicate these claims. We were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint.

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 and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO2 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. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court.

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 $7 million in 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, 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. I&M is repairing Unit 1 to resume operations as early as the fourth quarter of 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 September 30, 2009, we recorded $122 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. Through September 30, 2009, I&M received partial payments of $72 million 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 $145 million in revenue and applied $59 million of the accidental outage insurance proceeds to reduce customer bills.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. 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.

Fort Wayne Lease

Since 1975 I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expires on February 28, 2010. I&M has been negotiating with Fort Wayne to purchase the assets at the end of the lease, but no agreement has been reached. Recent mediation with Fort Wayne was also unsuccessful. Fort Wayne issued a technical notice of default under the lease to I&M in August 2009. I&M responded to Fort Wayne in October 2009 that it did not agree there was a default under the lease. In October 2009, I&M filed for declaratory and injunctive relief in Indiana state court. I&M will seek recovery in rates for any amount it may pay related to this dispute. At this time, management cannot predict the outcome of this dispute or its potential impact on net income or cash flows.

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 on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing 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. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed this award and posted bond covering that amount. In September 2009, the United States Court of Appeals for the Second Circuit heard oral argument on our appeal of the lower court's decision.

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 $439 million and $433 million including interest at September 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. Trial is scheduled for December 2009. 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. In September 2009, the parties reached a settlement. We reversed a portion of a provision recorded in 2008.

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 DHLC 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 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 diversifying 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 amounts in 2009 and 2008 related to discontinued operations:

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

U.K. Generation (a)

Nine Months Ended September 30,	(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 nine months ended September 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 nine months ended September 30, 2009 and 2008:

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 11	$ 10
Interest Cost	64	62	27	28
Expected Return on Plan Assets	(80)	(84)	(21)	(27)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	14	10	11	3
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 21

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 78	$ 75	$ 32	$ 31
Interest Cost	191	187	82	84
Expected Return on Plan Assets	(241)	(252)	(61)	(83)
Amortization of Transition Obligation	-	-	20	21
Amortization of Net Actuarial Loss	44	29	32	8
Net Periodic Benefit Cost	$ 72	$ 39	$ 105	$ 61

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 nine months ended September 30, 2009 and 2008 and balance sheet information as of September 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 September 30, 2009						
Revenues from:						
External Customers	$ 3,364 (d)	$ 113	$ 68	$ 2	$ -	$ 3,547
Other Operating Segments	25 (d)	4	-	1	(30)	-
Total Revenues	$ 3,389	$ 117	$ 68	$ 3	$ (30)	$ 3,547

Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 448	$ 10	$ 5	$ (17)	$ -	$ 446
Extraordinary Loss, Net of Tax	-	-	-	-	-	-
Net Income (Loss)	448	10	5	(17)	-	446
Less: Net Income Attributable to Noncontrolling Interests	2	-	-	-	-	2
Net Income (Loss) Attributable to AEP Shareholders	446	10	5	(17)	-	444
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	-	-	-	-	1
Earnings (Loss) Attributable to AEP Common Shareholders	$ 445	$ 10	$ 5	$ (17)	$ -	$ 443

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Three Months Ended September 30, 2008						
Revenues from:						
External Customers	$ 4,108 (d)	$ 160	$ 1	$ (78)	$ -	$ 4,191
Other Operating Segments	(140)(d)	7	95	83	(45)	-
Total Revenues	$ 3,968	$ 167	$ 96	$ 5	$ (45)	$ 4,191
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 359	$ 11	$ 16	$ (10)	$ -	$ 376
Discontinued Operations, Net of Tax	-	-	-	-	-	-
Net Income (Loss)	359	11	16	(10)	-	376
Less: Net Income Attributable to Noncontrolling Interests	1	-	-	-	-	1
Net Income (Loss) Attributable to AEP Shareholders	358	11	16	(10)	-	375
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	-	-	-	-	1
Earnings (Loss) Attributable to AEP Common Shareholders	$ 357	$ 11	$ 16	$ (10)	$ -	$ 374

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Nine Months Ended September 30, 2009						
Revenues from:						
External Customers	$ 9,666 (d)	$ 341	$ 213	$ (13)	$ -	$ 10,207
Other Operating Segments	46 (d)	13	6	28	(93)	-
Total Revenues	$ 9,712	$ 354	$ 219	$ 15	$ (93)	$ 10,207
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 1,121	$ 22	$ 33	$ (45)	$ -	$ 1,131
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	1,116	22	33	(45)	-	1,126
Less: Net Income Attributable to Noncontrolling Interests	5	-	-	-	-	5
Net Income (Loss) Attributable to AEP Shareholders	1,111	22	33	(45)	-	1,121
Less: Preferred Stock Dividend Requirements of Subsidiaries	2	-	-	-	-	2
Earnings (Loss) Attributable to AEP Common Shareholders	$ 1,109	$ 22	$ 33	$ (45)	$ -	$ 1,119

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Nine Months Ended September 30, 2008						
Revenues from:						
External Customers	$ 10,318 (d)	$ 442	$ 409	$ 35	$ -	$ 11,204
Other Operating Segments	257 (d)	18	(143)	(17)	(115)	-
Total Revenues	$ 10,575	$ 460	$ 266	$ 18	$ (115)	$ 11,204
Income Before Discontinued Operations and Extraordinary Loss	$ 1,036	$ 21	$ 43	$ 133	$ -	$ 1,233
Discontinued Operations, Net of Tax	-	-	-	1	-	1
Net Income	1,036	21	43	134	-	1,234
	4	-	-	-	-	4

Less: Net Income Attributable to Noncontrolling Interests						
Net Income Attributable to AEP Shareholders	1,032	21	43	134	-	1,230
Less: Preferred Stock Dividend Requirements of Subsidiaries	2	-	-	-	-	2
Earnings Attributable to AEP Common Shareholders	$ 1,030	$ 21	$ 43	$ 134	$ -	$ 1,228

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (c)	Consolidated
			(in millions)			
September 30, 2009						
Total Property, Plant and Equipment	$ 50,392	$ 423	$ 570	$ 10	$ (237)	$ 51,158
Accumulated Depreciation and Amortization	17,114	84	161	8	(30)	17,337
Total Property, Plant and Equipment – Net	$ 33,278	$ 339	$ 409	$ 2	$ (207)	$ 33,821
Total Assets	$ 45,776	$ 467	$ 791	$ 15,436	$ (15,277)(b)	$ 47,193

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustment (c)	Consolidated
December 31, 2008			(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 $(113) thousand and $(95) million for the three months ended September 30, 2009 and 2008, respectively, and $(6) million and $143 million for the nine months ended September 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 risks 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 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 the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

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 September 30, 2009:

Notional Volume of Derivative Instruments
September 30, 2009

Primary Risk Exposure	Volume	Unit of Measure

		(in millions)	
Commodity:			
Power		544	MWHs
Coal		61	Tons
Natural Gas		153	MMBtu
Heating Oil and Gasoline		8	Gallons
Interest Rate	$	216	USD
Interest Rate and Foreign Currency	$	89	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

The accounting guidance for “Derivatives and Hedging” 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 the accounting guidance for "Derivatives and Hedging," 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 September 30, 2009 and December 31, 2008 balance sheets, we netted $29 million and $11 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $100 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 September 30, 2009:

Fair Value of Derivative Instruments
September 30, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in millions)		
Current Risk Management Assets	$ 1,518	$ 24	$ -	$ (1,242)	$ 300
Long-term Risk Management Assets	828	4	-	(453)	379
Total Assets	2,346	28	-	(1,695)	679
Current Risk Management Liabilities	1,399	24	3	(1,290)	136
Long-term Risk Management Liabilities	643	10	2	(505)	150
Total Liabilities	2,042	34	5	(1,795)	286
Total MTM Derivative Contract Net Assets (Liabilities)	$ 304	$ (6)	$ (5)	$ 100	$ 393

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Consolidated Balance Sheet on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b)

Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
	(in millions)	
Utility Operations Revenue	$ 25	$ 124
Other Revenue	1	19
Regulatory Assets	(1)	(2)
Regulatory Liabilities	49	130
Total Gain on Risk Management Contracts	$ 74	$ 271

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on 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 on 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 some 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 the accounting guidance for "Regulated Operations."

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 nine months ended September 30, 2009, we did not employ any fair value hedging strategies. During the three and nine months ended September 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 on our Condensed Consolidated Statements of Income, or Regulatory Assets or Regulatory Liabilities on our Condensed Consolidated Balance Sheet, 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 nine months ended September 30, 2009 and 2008, we recognized immaterial amounts 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 nine months ended September 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 nine months ended September 30, 2009, we recognized a $1 million loss and a $6 million gain, respectively, in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated as cash flow hedges. During the three and nine months ended September 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 on 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 nine months ended September 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 nine months ended September 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 September 30, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Beginning Balance in AOCI as of July 1, 2009	$6	$(11)	$(5)
Changes in Fair Value Recognized in AOCI	(6)	(4)	(10)

Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Utility Operations Revenue	(7)	-	(7)
Other Revenue	(5)	-	(5)
Purchased Electricity for Resale	10	-	10
Interest Expense	-	1	1
Regulatory Assets	2	-	2
Regulatory Liabilities	(3)	-	(3)
Ending Balance in AOCI as of September 30, 2009	$(3)	$(14)	$(17)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 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	(9)	11	2
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Utility Operations Revenue	(13)	-	(13)
Other Revenue	(11)	-	(11)
Purchased Electricity for Resale	24	-	24
Interest Expense	-	4	4
Regulatory Assets	5	-	5
Regulatory Liabilities	(6)	-	(6)
Ending Balance in AOCI as of September 30, 2009	$(3)	$(14)	$(17)

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

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 17	$ -	$ 17
Hedging Liabilities (a)	(23)	(5)	(28)
AOCI Gain (Loss) Net of Tax	(3)	(14)	(17)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	1	(4)	(3)

(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 September 30, 2009, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 38 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 September 30, 2009, the aggregate value of such contracts was $36 million and we were not required to post any collateral. We would have been required to post $36 million of collateral at September 30, 2009 if our credit ratings had declined below investment grade of which $30 million was attributable to our RTO and ISO activities.

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under borrowed debt in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. As of September 30, 2009, the fair value of derivative liabilities subject to cross-default provisions totaled $852 million prior to consideration of contractual netting arrangements. This exposure has been reduced by cash collateral posted of $14 million. We believe that a non-performance event under these provisions is unlikely. If a cross-default provision would have been triggered, a settlement of up to $240 million would be required after considering our contractual netting arrangements.

9. FAIR VALUE MEASUREMENTS

With the adoption of new accounting guidance, we are required to provide certain fair value disclosures which we previously were only required to provide in our annual report. The new accounting guidance 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 September 30, 2009 and December 31, 2008 are summarized in the following table:

	September 30, 2009		December 31, 2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,253	$ 18,251	$ 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 captive 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 “Investments – Debt and Equity Securities” accounting guidance. 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:

	September 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)	$ 167	$ -	$ -	$ 167	$ 243	$ -	$ -	$ 243
Debt Securities	57	-	-	57	56	-	-	56
Equity Securities	18	17	-	35	27	11	10	28
Total Other Temporary Investments	$ 242	$ 17	$ -	$ 259	$ 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 nine months ended September 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	$ -	$ -
Nine Months Ended	-	2	-	-

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 captive insurance company. At September 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 September 30, 2009, the fair value of debt securities are primarily debt based mutual funds with short and intermediate 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 September 30, 2009 and December 31, 2008:

	September 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	$ 19	$ -	$ -	$ 18	$ -	$ -
Debt Securities	780	35	(2)	773	52	(3)
Equity Securities	565	223	(135)	469	89	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,364	$ 258	$ (137)	$ 1,260	$ 141	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 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	$ 113	$ 129	$ 1	$ -
Nine months Ended	524	571	10	(1)

The adjusted cost of debt securities was $745 million and $721 million as of September 30, 2009 and December 31, 2008, respectively.

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

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 27
1 year – 5 years	217
5 years – 10 years	241
After 10 years	295
Total	$ 780

Fair Value Measurements of Financial Assets and Liabilities

As described in our 2008 Annual Report, the accounting guidance for “Fair Value Measurements and Disclosures” 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 September 30, 2009 and December 31, 2008. As required by the accounting guidance for “Fair Value Measurements and Disclosures,” 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 September 30, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 799	$ -	$ -	$ 78	$ 877
Other Temporary Investments					
Cash and Cash Equivalents (a)	142	-	-	25	167
Debt Securities (c)	57	-	-	-	57
Equity Securities (d)	35	-	-	-	35
Total Other Temporary Investments	234	-	-	25	259
Risk Management Assets					
Risk Management Contracts (e)	21	2,195	116	(1,699)	633
Cash Flow Hedges (e)	3	24	-	(10)	17
Dedesignated Risk Management Contracts (f)	-	-	-	29	29
Total Risk Management Assets	24	2,219	116	(1,680)	679
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (g)	-	10	-	9	19
Debt Securities (h)	-	780	-	-	780
Equity Securities (d)	565	-	-	-	565
Total Spent Nuclear Fuel and Decommissioning Trusts	565	790	-	9	1,364
Total Assets	$ 1,622	$ 3,009	$ 116	$ (1,568)	$ 3,179
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (e)	$ 23	$ 1,993	$ 12	$ (1,770)	$ 258
Cash Flow Hedges (e)	5	33	-	(10)	28
Total Risk Management Liabilities	$ 28	$ 2,026	$ 12	$ (1,780)	$ 286

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 the accounting guidance for "Derivatives and Hedging."
(f) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." 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 September 30, 2009	Net Risk Management Assets (Liabilities)	Other Temporary Investments (in millions)	Investments in Debt Securities
Balance as of July 1, 2009	$ 67	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(8)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	10	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	-	-
Transfers in and/or out of Level 3 (c)	7	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	28	-	-
Balance as of September 30, 2009	$ 104	$ -	$ -

Nine Months Ended September 30, 2009	Net Risk Management Assets (Liabilities)	Other Temporary Investments (in millions)	Investments in Debt Securities
Balance as of January 1, 2009	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(21)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	51	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	-	-
Transfers in and/or out of Level 3 (c)	(26)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	51	-	-
Balance as of September 30, 2009	$ 104	$ -	$ -

Three Months Ended September 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments (in millions)	Investments in Debt Securities
Balance as of July 1, 2008	$ (8)	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	17	-	-
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)	(10)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	15	-	-
Balance as of September 30, 2008	$ 7	$ -	$ -

Nine Months Ended September 30, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments (in millions)	Investments in Debt Securities
Balance as of January 1, 2008	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	-	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	4	-	-
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)	(35)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(11)	-	-
Balance as of September 30, 2008	$ 7	$ -	$ -

(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. The years 2007 and 2008 are currently under examination. 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.

We are changing the tax method of accounting for the definition of a unit of property for generation assets. This change will provide a favorable cash flow benefit in 2009 and 2010.

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 were primarily used to repay cash drawn under our credit facilities in the second quarter of 2009.

Long-term Debt

Type of Debt	September 30, 2009	December 31, 2008
	(in millions)	
Senior Unsecured Notes	$ 12,316	$ 11,069
Pollution Control Bonds	2,055	1,946
Notes Payable	288	233
Securitization Bonds	1,995	2,132
Junior Subordinated Debentures	315	315
Spent Nuclear Fuel Obligation (a)	264	264
Other Long-term Debt	87	88
Unamortized Discount (net)	(67)	(64)
Total Long-term Debt Outstanding	17,253	15,983
Less Portion Due Within One Year	1,540	447
Long-term Portion	$ 15,713	$ 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 $306 million and $301 million at September 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 nine months of 2009 are shown in the tables below.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 350	7.95	2020
CSPCo	Pollution Control Bonds	60	3.875	2038
CSPCo	Pollution Control Bonds	32	5.80	2038
I&M	Senior Unsecured Notes	475	7.00	2019
I&M	Notes Payable	102	5.44	2013
I&M	Pollution Control Bonds	50	6.25	2025
I&M	Pollution Control Bonds	50	6.25	2025
OPCo	Senior Unsecured Notes	500	5.375	2021
PSO	Pollution Control Bonds	34	5.25	2014
Non-Registrant:				
AEP River Operations	Notes Payable	49	7.59	2026
KPCo	Senior Unsecured Notes	40	7.25	2021
KPCo	Senior Unsecured Notes	30	8.03	2029
KPCo	Senior Unsecured Notes	60	8.13	2039
TCC	Pollution Control Bonds	101	6.30	2029
Total Issuances		$ 1,933 (a)		

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

(a) Amount indicated on the statement of cash flows of $1,912 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	Pollution Control Bonds	218	Variable	2028-2029
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	3	4.47	2011
Non-Registrant:				
AEP Subsidiaries	Notes Payable	11	Variable	2017
AEP Subsidiaries	Notes Payable	4	5.88	2011
AEGCo	Senior Unsecured Notes	7	6.33	2037
TCC	Securitization Bonds	54	5.56	2010
TCC	Securitization Bonds	84	4.98	2010
		$ 659		

Total Retirements and Principal Payments	

In October 2009, AEP River Operations issued $45 million of 8.03% Notes Payable due in 2026.

During 2008, we chose to begin eliminating our auction-rate debt position due to market conditions. As of September 30, 2009, $54 million of our auction-rate tax-exempt long-term debt remained outstanding at a rate of 0.862% that resets 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. In the third quarter of 2009, we reacquired $218 million of auction-rate debt related to JMG with interest rates at the contractual maximum rate of 13%. We were unable to refinance the 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 which enabled us to reacquire this debt.

As of September 30, 2009, trustees held, on our behalf, $321 million of our reacquired auction-rate tax-exempt long-term debt, which includes the $218 million related to JMG. We plan to reissue the debt.

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:

	September 30, 2009			December 31, 2008		
Type of Debt		Outstanding Amount (in thousands)	Interest Rate (a)		Outstanding Amount (in thousands)	Interest Rate (a)
Line of Credit – AEP (b)	$	-	-	$	1,969,000	2.28%(c)
Line of Credit – Sabine Mining Company (d)		5,273	1.60%		7,172	1.54%
Commercial Paper – AEP		347,000	0.45%		-	-
Total	$	352,273		$	1,976,172	

(a) Weighted average rate.
(b) Paid primarily with proceeds from the April 2009 equity issuance.
(c) Rate based on LIBOR.
(d) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

As of September 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 September 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

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash.

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. The previous sale of receivables agreement provided a commitment of $700 million.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2009 Compared to Third Quarter of 2008

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

Third Quarter of 2008		$39
Changes in Gross Margin:		
Retail Margins	77	
Off-system Sales	(65)	
Total Change in Gross Margin		12
Total Expenses and Other:		
Other Operation and Maintenance	(4)	
Depreciation and Amortization	(7)	
Carrying Costs Income	(5)	
Other Income	(3)	
Interest Expense	(5)	
Total Expenses and Other		(24)
Third Quarter of 2009		$27

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 $77 million primarily due to the following:
  - A $54 million increase due to a decrease in off-system sales margins shared with customers in Virginia and West Virginia.
  - A $37 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.

  These increases were partially offset by:
  - A $9 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
  - A $5 million decrease in industrial sales primarily due to suspended operations by APCo's largest customer, Century Aluminum.
- Margins from Off-system Sales decreased $65 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading and marketing margins.

Total Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $4 million primarily due to the following:
  - A $9 million increase related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia's share of previously expended NSR settlement costs. See "Virginia Rate Matters – Virginia E&R Costs Recovery Filing" section of Note 3.
  - A $2 million increase related to generation plant maintenance.

  These increases were partially offset by:
  - An $8 million decrease related to the establishment of a regulatory asset for the deferral of transmission costs. See "Virginia Rate Matters – Rate Adjustment Clauses" section of Note 3.
- Depreciation and Amortization expenses increased $7 million primarily due to increased assets to depreciate reflecting environmental upgrades at the Amos and Clinch River Plants.
- Carrying Costs Income decreased $5 million due to completion of reliability deferrals in Virginia in December 2008 and a decrease of environmental deferrals in Virginia in 2009.
- Interest Expense increased $5 million primarily due to an increase in long-term borrowings.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Reconciliation of Nine Months Ended September 30, 2008 to Nine Months Ended September 30, 2009
Net Income
(in millions)

Nine Months Ended September 30, 2008		$ 121
Changes in Gross Margin:		
Retail Margins	230	
Off-system Sales	(159)	
Total Change in Gross Margin		71
Total Expenses and Other:		
Other Operation and Maintenance	16	
Depreciation and Amortization	(17)	
Carrying Costs Income	(23)	
Other Income	(7)	
Interest Expense	(15)	
Total Expenses and Other		(46)
Income Tax Expense		(15)
Nine Months Ended September 30, 2009		$ 131

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 $230 million primarily due to the following:
  - A $128 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 $124 million increase due to a decrease in off-system sales margins shared with customers in Virginia and West Virginia.

- A $19 million increase due to new rates effective January 2009 for a power supply contract with KGPCo.

These increases were partially offset by:

- A $37 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
- A $15 million decrease in industrial sales primarily due to suspended operations by APCo's largest customer, Century Aluminum.

- Margins from Off-system Sales decreased $159 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading and marketing margins.

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

- Other Operation and Maintenance expenses decreased $16 million primarily due to the following:
  - A $14 million decrease related to the establishment of a regulatory asset in 2009 for the deferral of transmission costs. See "Virginia Rate Matters – Rate Adjustment Clauses" section of Note 3.
  - A $6 million decrease in employee benefit expenses.
  - A $2 million decrease in generation plant maintenance.

  These decreases were partially offset by:
  - A $9 million increase related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia's share of previously expended NSR settlement costs. See "Virginia Rate Matters – Virginia E&R Costs Recovery Filing" section of Note 3.
- Depreciation and Amortization expenses increased $17 million primarily due to increased assets to depreciate reflecting environmental upgrades at the Amos and Clinch River Plants and the amortization of carrying charges and depreciation expenses that are being collected through the Virginia E&R surcharges.
- Carrying Costs Income decreased $23 million due to completion of reliability deferrals in Virginia in December 2008 and a decrease of environmental deferrals in Virginia in 2009.
- Interest Expense increased $15 million primarily due to an increase in long-term borrowings.
- Other Income decreased $7 million primarily due to higher interest income that was recorded in 2008 related to a tax refund and other tax adjustments.
- Income Tax Expense increased $15 million primarily due to an increase in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

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

S&P has APCo on stable outlook. In February 2009, Moody's changed its rating outlook for APCo from negative to stable. In September 2009, Fitch 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 nine months ended September 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	(53,712)	208,445
Investing Activities	(406,707)	(472,029)
Financing Activities	460,237	263,376
Net Decrease in Cash and Cash Equivalents	(182)	(208)
Cash and Cash Equivalents at End of Period	$ 1,814	$ 1,987

Operating Activities

Net Cash Flows Used for Operating Activities were $54 million in 2009. APCo produced Net Income of $131 million during the period and had noncash expense items of $229 million for Deferred Income Taxes and $204 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. The $160 million outflow from Fuel, Materials and Supplies was primarily due to an increase in coal inventory. The $132 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 of 2009 to the AEP West companies as part of a FERC order on the SIA. The $52 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 $181 million change in Fuel Over/Under-Recovery, Net resulted from a net under-recovery of fuel cost in both Virginia and West Virginia.

Net Cash Flows from Operating Activities were $208 million in 2008. APCo produced Net Income of $121 million during the period and had noncash expense items of $187 million for Depreciation and Amortization and $111 million for Deferred Income Taxes, partially offset by $39 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 $42 million inflow from Accounts Payable primarily due to an increase in fuel costs. The $114 million change in Fuel Over/Under-Recovery, Net resulted from higher fuel costs in Virginia and the 2009 approval of a four-year phase-in plan for ENEC recovery in West Virginia.

Investing Activities

Net Cash Flows Used for Investing Activities during 2009 and 2008 were $407 million and $472 million, respectively. Construction Expenditures were $420 million and $488 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.

Financing Activities

Net Cash Flows from Financing Activities were $460 million in 2009. APCo issued $350 million of Senior Unsecured Notes in March 2009 and retired $150 million of Senior Unsecured Notes in May 2009. APCo received capital contributions from the Parent of $250 million in the second quarter of 2009. APCo had a net increase of $37 million in borrowings from the Utility Money Pool. In addition, APCo paid $20 million in dividends on common stock.

Net Cash Flows from Financing Activities were $263 million in 2008. APCo issued $500 million of Senior Unsecured Notes in March 2008, $125 million of Pollution Control Bonds in June 2008 and $70 million of Pollution Control Bonds in September 2008. APCo retired $213 million of Pollution Control Bonds and $200 million of Senior Unsecured Notes in the second quarter of 2008. APCo had a net decrease of $182 million in borrowings from the Utility Money Pool. In addition, APCo received capital contributions from the Parent of $175 million.

Financing Activity

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

Issuances

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

Retirements and Principal Payments

Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$ 150,000	6.60	2009
Land Note	12	13.718	2026

Liquidity

Although the financial markets were volatile at both a global and domestic level, APCo issued $350 million of Senior Unsecured Notes during the first nine months of 2009. The credit situation appears to have improved but could impact APCo's future 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 relies 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 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. 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 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 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. 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 September 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
September 30, 2009
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedge Contracts	DETM Assignment (a)	Collateral Deposits	Total
Current Assets	$ 85,559	$2,818	$-	$(4,942)	$83,435
Noncurrent Assets	61,936	553	-	(4,737)	57,752
Total MTM Derivative Contract Assets	147,495	3,371	-	(9,679)	141,187
Current Liabilities	42,005	2,397	2,767	(16,167)	31,002
Noncurrent Liabilities	38,585	996	697	(16,624)	23,654
Total MTM Derivative Contract Liabilities	80,590	3,393	3,464	(32,791)	54,656
Total MTM Derivative Contract Net Assets (Liabilities)	$ 66,905	$(22)	$(3,464)	$23,112	$86,531

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 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	(24,390)
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	(185)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(530)

Changes in Fair Value Allocated to Regulated Jurisdictions (c)	35,074
Total MTM Risk Management Contract Net Assets	66,905
Cash Flow Hedge Contracts	(22)
DETM Assignment (d)	(3,464)
Collateral Deposits	23,112
Total MTM Derivative Contract Net Assets at September 30, 2009	$86,531

(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 on 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 or (require) cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
September 30, 2009
(in thousands)

	Remainder 2009	2010	2011	2012	2013	After 2013	Total
Level 1 (a)	$ (444)	$ (48)	$ 1	$ -	$ -	$ -	$ (491)
Level 2 (b)	8,411	14,350	6,979	983	2,758	220	33,701
Level 3 (c)	6,659	13,812	2,118	1,085	(26)	-	23,648
Total	14,626	28,114	9,098	2,068	2,732	220	56,858
Dedesignated Risk Management Contracts (d)	1,444	4,951	1,928	1,724	-	-	10,047
Total MTM Risk Management Contract Net Assets	$ 16,070	$ 33,065	$ 11,026	$ 3,792	$ 2,732	$ 220	$ 66,905

(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 the accounting guidance for "Derivatives and Hedging." 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 September 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:

Nine Months Ended September 30, 2009 (in thousands)				Twelve Months Ended December 31, 2008 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$258	$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 September 30, 2009, the estimated EaR on APCo's debt portfolio for the following twelve months was $3.5 million.

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

	Three Months Ended		Nine Months Ended	
	2009	2008	2009	2008
REVENUES				
Electric Generation, Transmission and Distribution	$629,566	$719,295	$1,929,552	$1,926,841
Sales to AEP Affiliates	63,645	74,632	181,914	262,230
Other Revenues	2,462	4,906	6,348	12,186
TOTAL REVENUES	695,673	798,833	2,117,814	2,201,257
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	140,321	220,955	402,893	554,022
Purchased Electricity for Resale	54,087	71,075	189,534	167,205
Purchased Electricity from AEP Affiliates	202,043	219,595	570,231	595,433
Other Operation	68,402	66,316	197,441	210,262
Maintenance	53,164	51,292	158,552	161,371
Depreciation and Amortization	69,701	62,364	203,844	186,528
Taxes Other Than Income Taxes	24,257	24,319	72,156	72,414
TOTAL EXPENSES	611,975	715,916	1,794,651	1,947,235
OPERATING INCOME	83,698	82,917	323,163	254,022
Other Income (Expense):				
Interest Income	301	1,945	1,078	7,541
Carrying Costs Income	6,467	11,924	16,341	38,921
Allowance for Equity Funds Used During Construction	1,897	2,130	5,734	6,278
Interest Expense	(51,982)	(47,385)	(153,144)	(138,644)
INCOME BEFORE INCOME TAX EXPENSE	40,381	51,531	193,172	168,118
Income Tax Expense	13,011	12,516	62,225	47,508
NET INCOME	27,370	39,015	130,947	120,610
Preferred Stock Dividend Requirements Including Capital Stock Expense	225	238	675	714
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$27,145	$38,777	$130,272	$119,896

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 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		175,000			175,000
Preferred Stock Dividends			(599)		(599)
Capital Stock Expense		115	(115)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,253,966
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $677				(1,258)	(1,258)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,346				2,499	2,499
NET INCOME			120,610		120,610
TOTAL COMPREHENSIVE INCOME					121,851
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2008	$260,458	$1,200,264	$949,041	$ (33,946)	$2,375,817
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			(599)		(599)
Capital Stock Expense		76	(76)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,605,992
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $545				(1,013)	(1,013)

Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,982				3,680	3,680
NET INCOME			130,947		130,947
TOTAL COMPREHENSIVE INCOME					133,614
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2009	$260,458	$1,475,368	$1,061,338	$ (57,558)	$2,739,606

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$1,814	$1,996
Accounts Receivable:		
Customers	126,428	175,709
Affiliated Companies	121,925	110,982
Accrued Unbilled Revenues	47,736	55,733
Miscellaneous	768	498
Allowance for Uncollectible Accounts	(5,426)	(6,176)
Total Accounts Receivable	291,431	336,746
Fuel	282,835	131,239
Materials and Supplies	84,568	76,260
Risk Management Assets	83,435	65,140
Accrued Tax Benefits	88,542	15,599
Regulatory Asset for Under-Recovered Fuel Costs	92,629	165,906
Prepayments and Other Current Assets	46,879	45,657
TOTAL CURRENT ASSETS	972,133	838,543
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,214,909	3,708,850
Transmission	1,797,755	1,754,192
Distribution	2,606,423	2,499,974
Other Property, Plant and Equipment	358,696	358,873
Construction Work in Progress	661,531	1,106,032
Total Property, Plant and Equipment	9,639,314	9,427,921
Accumulated Depreciation and Amortization	2,752,839	2,675,784
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,886,475	6,752,137
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,329,527	999,061
Long-term Risk Management Assets	57,752	51,095
Deferred Charges and Other Noncurrent Assets	96,180	121,828
TOTAL OTHER NONCURRENT ASSETS	1,483,459	1,171,984
TOTAL ASSETS	$9,342,067	$8,762,664

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$231,788	$194,888
Accounts Payable:		
General	195,277	358,081
Affiliated Companies	111,723	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	31,002	30,620
Customer Deposits	57,804	54,086
Deferred Income Taxes	74,192	-
Accrued Taxes	42,531	65,550
Accrued Interest	69,748	47,804
Other Current Liabilities	70,346	113,655
TOTAL CURRENT LIABILITIES	1,184,429	1,221,514
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,072,342	2,924,495
Long-term Debt – Affiliated	-	100,000
Long-term Risk Management Liabilities	23,654	26,388
Deferred Income Taxes	1,316,661	1,131,164
Regulatory Liabilities and Deferred Investment Tax Credits	547,099	521,508
Employee Benefits and Pension Obligations	323,237	331,000
Deferred Credits and Other Noncurrent Liabilities	117,287	112,252
TOTAL NONCURRENT LIABILITIES	5,400,280	5,146,807
TOTAL LIABILITIES	6,584,709	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	1,475,368	1,225,292
Retained Earnings	1,061,338	951,066
Accumulated Other Comprehensive Income (Loss)	(57,558)	(60,225)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,739,606	2,376,591
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$9,342,067	$8,762,664

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
OPERATING ACTIVITIES		
Net Income	$130,947	$120,610
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	203,844	186,528
Deferred Income Taxes	229,246	111,297
Carrying Costs Income	(16,341)	(38,921)
Allowance for Equity Funds Used During Construction	(5,734)	(6,278)
Mark-to-Market of Risk Management Contracts	(31,415)	7,450
Fuel Over/Under-Recovery, Net	(181,241)	(113,748)
Change in Other Noncurrent Assets	(38,470)	(24,670)
Change in Other Noncurrent Liabilities	22,595	(12,565)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	51,667	(12,313)
Fuel, Materials and Supplies	(159,904)	3,483
Accounts Payable	(131,914)	41,869
Accrued Taxes, Net	(95,962)	(51,208)
Other Current Assets	(14,172)	(17,202)
Other Current Liabilities	(16,858)	14,113
Net Cash Flows from (Used for) Operating Activities	(53,712)	208,445
INVESTING ACTIVITIES		
Construction Expenditures	(420,075)	(487,797)
Change in Other Cash Deposits	235	(18)
Acquisitions of Assets	(1,024)	-
Proceeds from Sales of Assets	14,157	15,786
Net Cash Flows Used for Investing Activities	(406,707)	(472,029)
FINANCING ACTIVITIES		
Capital Contribution from Parent	250,000	175,000
Issuance of Long-term Debt – Nonaffiliated	345,658	686,512
Change in Advances from Affiliates, Net	36,900	(181,699)
Retirement of Long-term Debt – Nonaffiliated	(150,012)	(412,786)
Principal Payments for Capital Lease Obligations	(2,582)	(3,052)
Dividends Paid on Common Stock	(20,000)	-
Dividends Paid on Cumulative Preferred Stock	(599)	(599)
Other Financing Activities	872	-
Net Cash Flows from Financing Activities	460,237	263,376
Net Decrease in Cash and Cash Equivalents	(182)	(208)
Cash and Cash Equivalents at Beginning of Period	1,996	2,195
Cash and Cash Equivalents at End of Period	$1,814	$1,987

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$148,745	$110,349
Net Cash Received for Income Taxes	(14,679)	(26,330)
Noncash Acquisitions Under Capital Leases	884	1,246
Construction Expenditures Included in Accounts Payable at September 30,	56,989	112,376

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2009 Compared to Third Quarter of 2008

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

Third Quarter of 2008		$82
Changes in Gross Margin:		
Retail Margins	33	
Off-system Sales	(41)	
Total Change in Gross Margin		(8)
Total Expenses and Other:		
Other Operation and Maintenance	18	
Depreciation and Amortization	14	
Other Income	(1)	
Interest Expense	(1)	
Total Expenses and Other		30
Income Tax Expense		(6)
Third Quarter of 2009		$98

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 $33 million primarily due to:
  - A $37 million increase related to the implementation of higher rates set by the Ohio ESP.
  - A $35 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 $16 million decrease in residential and commercial revenue primarily due to a 30% decrease in cooling degree days.
  - A $13 million decrease in industrial sales primarily due to reduced operating levels by CSPCo's largest industrial customer, Ormet.
  - A $13 million decrease related to the cessation of Restructuring Transition Charge (RTC) revenues with the implementation of rates under the Ohio ESP.

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Margins from Off-system Sales decreased $41 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading and marketing margins.

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

- Other Operation and Maintenance expenses decreased $18 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 $6 million decrease in recoverable PJM expenses.
  - A $2 million decrease in employee benefit expenses.
- Depreciation and Amortization decreased $14 million primarily due to the completed amortization of transition regulatory assets in December 2008.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Reconciliation of Nine Months Ended September 30, 2008 to Nine Months Ended September 30, 2009
Net Income
(in millions)

Nine Months Ended September 30, 2008		$214
Changes in Gross Margin:		
Retail Margins	63	
Off-system Sales	(92)	
Transmission Revenues	(1)	
Other	(1)	
Total Change in Gross Margin		(31)
Total Expenses and Other:		
Other Operation and Maintenance	29	
Depreciation and Amortization	41	
Taxes Other Than Income Taxes	(2)	
Other Income	(4)	
Interest Expense	(7)	
Total Expenses and Other		57
Income Tax Expense		(9)
Nine Months Ended September 30, 2009		$231

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 $63 million primarily due to:
  - An $80 million increase related to the implementation of higher rates set by the Ohio ESP.
  -

A $57 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 $39 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 $25 million decrease in industrial sales primarily due to reduced operating levels by CSPCo's largest industrial customer, Ormet.
- A $10 million decrease in commercial revenue primarily due to reduced usage and an 18% decrease in cooling degree days.

- Margins from Off-system Sales decreased $92 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading and marketing margins.

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

- Other Operation and Maintenance expenses decreased $29 million primarily due to:
  - A $25 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 $6 million decrease in employee benefit expenses.
  - A $4 million decrease in recoverable PJM expenses.
  - A $3 million decrease in net allocated transmission expenses related to the AEP Transmission Equalization 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 $13 million increase in overhead distribution line expenses primarily due to ice and wind storms in the first quarter of 2009 and increased 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 CSPCo's ESP. See "Ohio Electric Security Plan Filings" section of Note 3.
- Depreciation and Amortization decreased $41 million primarily due to the completed amortization of transition regulatory assets in December 2008.
- Taxes Other Than Income Taxes increased $2 million primarily due to an increase in property taxes partially offset by a decrease in state excise 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 $7 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 $9 million primarily due to an increase in pretax book income.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 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 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 September 30, 2009, the estimated EaR on CSPCo's debt portfolio for the following twelve months was $112 thousand.

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

	Three Months Ended 2009	Three Months Ended 2008	Nine Months Ended 2009	Nine Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$533,306	$633,325	$1,482,421	$1,638,705
Sales to AEP Affiliates	22,143	29,032	51,514	111,553
Other Revenues	694	1,426	1,820	4,121
TOTAL REVENUES	556,143	663,783	1,535,755	1,754,379
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	88,523	112,566	222,943	283,946
Purchased Electricity for Resale	21,750	63,441	74,010	150,637
Purchased Electricity from AEP Affiliates	105,120	139,017	294,280	343,699
Other Operation	68,971	87,358	210,614	245,379
Maintenance	23,926	23,039	86,558	80,705
Depreciation and Amortization	36,292	50,373	105,863	146,668
Taxes Other Than Income Taxes	44,149	44,533	132,576	130,078
TOTAL EXPENSES	388,731	520,327	1,126,844	1,381,112
OPERATING INCOME	167,412	143,456	408,911	373,267
Other Income (Expense):				
Interest Income	144	1,515	618	5,457
Carrying Costs Income	1,984	1,566	5,394	4,870
Allowance for Equity Funds Used During Construction	914	745	2,799	2,165
Interest Expense	(22,487)	(21,127)	(64,356)	(57,612)
INCOME BEFORE INCOME TAX EXPENSE	147,967	126,155	353,366	328,147
Income Tax Expense	50,374	44,493	122,737	113,939
NET INCOME	97,593	81,662	230,629	214,208
Capital Stock Expense	39	39	118	118
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$97,554	$81,623	$230,511	$214,090

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 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			(87,500)		(87,500)
Capital Stock Expense		118	(118)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,075,366
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $582				1,080	1,080
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $456				846	846
NET INCOME			214,208		214,208
TOTAL COMPREHENSIVE INCOME					216,134
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2008	$41,026	$580,467	$686,875	$ (16,868)	$1,291,500
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$41,026	$580,506	$674,758	$ (51,025)	$1,245,265
Common Stock Dividends			(150,000)		(150,000)
Capital Stock Expense		118	(118)		-
Noncash Dividend of Property to Parent			(8,123)		(8,123)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,087,142
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $699				(1,299)	(1,299)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $894				1,661	1,661
NET INCOME			230,629		230,629

TOTAL COMPREHENSIVE INCOME					230,991
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2009	$41,026	$580,624	$747,146	$ (50,663)	$1,318,133

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,204	$ 1,063
Other Cash Deposits	20,077	32,300
Accounts Receivable:		
Customers	22,153	56,008
Affiliated Companies	20,176	44,235
Accrued Unbilled Revenues	24,878	18,359
Miscellaneous	2,141	11,546
Allowance for Uncollectible Accounts	(3,565)	(2,895)
Total Accounts Receivable	65,783	127,253
Fuel	72,204	42,075
Materials and Supplies	38,886	33,781
Emission Allowances	13,794	20,211
Risk Management Assets	43,916	35,984
Accrued Tax Benefits	18,023	469
Margin Deposits	17,652	13,613
Prepayments and Other Current Assets	9,616	27,411
TOTAL CURRENT ASSETS	301,155	334,160
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,372,111	2,326,056
Transmission	610,824	574,018
Distribution	1,699,698	1,625,000
Other Property, Plant and Equipment	201,890	211,088
Construction Work in Progress	399,388	394,918
Total Property, Plant and Equipment	5,283,911	5,131,080
Accumulated Depreciation and Amortization	1,844,261	1,781,866
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,439,650	3,349,214
OTHER NONCURRENT ASSETS		
Regulatory Assets	335,691	298,357
Long-term Risk Management Assets	30,569	28,461
Deferred Charges and Other Noncurrent Assets	72,798	125,814
TOTAL OTHER NONCURRENT ASSETS	439,058	452,632
TOTAL ASSETS	$4,179,863	$4,136,006

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$20,095	$74,865
Accounts Payable:		
General	88,992	131,417
Affiliated Companies	84,743	120,420
Long-term Debt Due Within One Year – Affiliated	100,000	-
Risk Management Liabilities	16,275	16,490
Customer Deposits	28,067	30,145
Accrued Taxes	100,021	185,293
Accrued Interest	26,776	23,867
Other Current Liabilities	67,275	58,811
TOTAL CURRENT LIABILITIES	532,244	641,308
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,436,291	1,343,594
Long-term Debt – Affiliated	-	100,000
Long-term Risk Management Liabilities	12,522	14,774
Deferred Income Taxes	511,102	435,773
Regulatory Liabilities and Deferred Investment Tax Credits	179,825	161,102
Employee Benefits and Pension Obligations	142,020	148,123
Deferred Credits and Other Noncurrent Liabilities	47,726	46,067
TOTAL NONCURRENT LIABILITIES	2,329,486	2,249,433
TOTAL LIABILITIES	2,861,730	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	580,624	580,506
Retained Earnings	747,146	674,758
Accumulated Other Comprehensive Income (Loss)	(50,663)	(51,025)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,318,133	1,245,265
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$4,179,863	$4,136,006

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
OPERATING ACTIVITIES		
Net Income	$230,629	$214,208
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	105,863	146,668
Deferred Income Taxes	97,279	8,981
Carrying Costs Income	(5,394)	(4,870)
Allowance for Equity Funds Used During Construction	(2,799)	(2,165)
Mark-to-Market of Risk Management Contracts	(14,832)	5,326
Deferred Property Taxes	67,012	65,763
Fuel Over/Under-Recovery, Net	(36,401)	-
Change in Other Noncurrent Assets	(18,365)	(7,942)
Change in Other Noncurrent Liabilities	22,644	(4,081)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	62,244	(13,757)
Fuel, Materials and Supplies	(28,817)	7,415
Accounts Payable	(56,723)	(2,650)
Customer Deposits	(2,078)	(13,100)
Accrued Taxes, Net	(102,827)	(26,358)
Other Current Assets	8,017	(13,178)
Other Current Liabilities	(5,914)	(14,018)
Net Cash Flows from Operating Activities	319,538	346,242
INVESTING ACTIVITIES		
Construction Expenditures	(216,737)	(304,175)
Change in Other Cash Deposits	12,223	21,796
Change in Advances to Affiliates, Net	-	(21,833)
Acquisitions of Assets	(227)	-
Proceeds from Sales of Assets	721	1,287
Net Cash Flows Used for Investing Activities	(204,020)	(302,925)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	91,204	346,407
Change in Advances from Affiliates, Net	(54,770)	(95,199)
Retirement of Long-term Debt – Nonaffiliated	-	(204,245)
Principal Payments for Capital Lease Obligations	(2,017)	(2,213)
Dividends Paid on Common Stock	(150,000)	(87,500)
Other Financing Activities	206	-
Net Cash Flows Used for Financing Activities	(115,377)	(42,750)
Net Increase in Cash and Cash Equivalents	141	567
Cash and Cash Equivalents at Beginning of Period	1,063	1,389
Cash and Cash Equivalents at End of Period	$1,204	$1,956

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$71,032	$57,004
Net Cash Paid for Income Taxes	10,997	53,682
Noncash Acquisitions Under Capital Leases	784	1,374
Construction Expenditures Included in Accounts Payable at September 30,	26,688	51,997
Noncash Dividend of Property to Parent	8,123	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

Results of Operations

Third Quarter of 2009 Compared to Third Quarter of 2008

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

Third Quarter of 2008		$46
Changes in Gross Margin:		
Retail Margins	(2)	
FERC Municipals and Cooperatives	1	
Off-system Sales	(39)	
Other	38	
Total Change in Gross Margin		(2)
Total Expenses and Other:		
Other Operation and Maintenance	17	
Depreciation and Amortization	(2)	
Other Income	4	
Interest Expense	(5)	
Total Expenses and Other		14
Income Tax Expense		(3)
Third Quarter of 2009		$55

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:

- Margins from Off-system Sales decreased $39 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading and marketing margins.
- Other revenues increased $38 million primarily due to Cook Plant accidental outage insurance policy proceeds of $46 million. Of these insurance proceeds, $19 million were used to reduce 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 $17 million primarily due to declines in operation and maintenance expenses of $9 million for nuclear operations and $8 million for RTD caused by decreased barging activity.
- Other Income increased $4 million due to higher equity AFUDC.

· Interest Expense increased $5 million primarily due to increased borrowings. In January 2009, I&M issued $475 million of 7% Senior Unsecured Notes.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Reconciliation of Nine Months Ended September 30, 2008 to Nine Months Ended September 30, 2009
Net Income
(in millions)

Nine Months Ended September 30, 2008		$ 151
Changes in Gross Margin:		
Retail Margins	(26)	
FERC Municipals and Cooperatives	5	
Off-system Sales	(94)	
Transmission Revenues	(1)	
Other	132	
Total Change in Gross Margin		16
Total Expenses and Other:		
Other Operation and Maintenance	43	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	2	
Other Income	8	
Interest Expense	(18)	
Total Expenses and Other		30
Income Tax Expense		(13)
Nine Months Ended September 30, 2009		$ 184

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 $26 million primarily due to the following:
  · A $37 million decline due to a 16% decrease in industrial sales resulting from reduced operating levels and suspended operations by certain large industrial customers.
  · Lower fuel recoveries reflecting $59 million of Cook Plant accidental outage insurance proceeds allocated to customers under fuel clauses.

  These decreases were partially offset by:
  · A $29 million increase in capacity revenue reflecting MLR changes.
  · A $26 million increase from an Indiana rate settlement. See “Indiana Base Rate Filing” section of Note 3.
  · A $17 million favorable impact for lower PJM charges reflecting a decline in sales volume.
· Margins from Off-system Sales decreased $94 million primarily due to lower physical sales volumes and lower margins as a result of lower market prices, partially offset by higher trading and marketing margins.
· Other revenues increased $132 million primarily due to Cook Plant accidental outage insurance policy proceeds of $145 million. Of the insurance proceeds, $59 million were used to reduce customer bills which are primarily included in Retail Margins. See “Cook Plant Unit 1 Fire and Shutdown” section of Note 4. A decrease in 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 and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $43 million primarily due to the following:
  - A $21 million decline for nuclear and coal-fired generating operation and maintenance expenses reflecting cost containment efforts, deferral of costs during outages and deferral of NSR costs provided in the rate settlement for recovery. See "Indiana Base Rate Filing" section of Note 3.
  - An $11 million decline for RTD caused by decreased barging activity.
  - A $7 million decline in accretion expense reflecting a change in the annual decommissioning estimate at Cook Plant for an extension of its life authorized in the rate settlement.
- Other Income increased $8 million due to higher equity AFUDC.
- Interest Expense increased $18 million primarily due to increased borrowings. In January 2009, I&M issued $475 million of 7% Senior Unsecured Notes.
- Income Tax Expense increased $13 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, 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. I&M is repairing Unit 1 to resume operations as early as the fourth quarter of 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 September 30, 2009, I&M recorded $122 million in Prepayments and Other Current Assets on the Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. Through September 30, 2009, I&M received partial payments of $72 million 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 $145 million in revenues and applied $59 million of the accidental outage insurance proceeds to reduce customer bills.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. 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 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 September 30, 2009, the estimated EaR on I&M's debt portfolio for the following twelve months was $2.3 million.

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

	Three Months Ended 2009	Three Months Ended 2008	Nine Months Ended 2009	Nine Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$435,399	$513,548	$1,257,673	$1,370,158
Sales to AEP Affiliates	43,796	72,295	161,167	232,734
Other Revenues – Affiliated	24,958	31,792	80,890	84,268
Other Revenues – Nonaffiliated	48,114	3,388	149,997	13,659
TOTAL REVENUES	552,267	621,023	1,649,727	1,700,819
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	105,287	141,563	316,449	351,300
Purchased Electricity for Resale	28,203	39,427	97,417	87,351
Purchased Electricity from AEP Affiliates	93,093	112,060	253,964	296,559
Other Operation	121,737	136,875	346,421	381,928
Maintenance	50,650	52,573	148,412	156,402
Depreciation and Amortization	34,032	31,822	100,406	95,301
Taxes Other Than Income Taxes	19,122	19,992	58,071	60,236
TOTAL EXPENSES	452,124	534,312	1,321,140	1,429,077
OPERATING INCOME	100,143	86,711	328,587	271,742
Other Income (Expense):				
Other Income	5,024	880	12,879	4,621
Interest Expense	(25,668)	(20,629)	(75,372)	(56,977)
INCOME BEFORE INCOME TAX EXPENSE	79,499	66,962	266,094	219,386
Income Tax Expense	24,640	21,326	81,774	68,348
NET INCOME	54,859	45,636	184,320	151,038
Preferred Stock Dividend Requirements	85	85	255	255
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$54,774	$45,551	$184,065	$150,783

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 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			(56,250)		(56,250)
Preferred Stock Dividends			(255)		(255)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,327,796
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $967				1,795	1,795
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $178				331	331
NET INCOME			151,038		151,038
TOTAL COMPREHENSIVE INCOME					153,164
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2008	$56,584	$861,291	$576,634	$ (13,549)	$1,480,960
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			(73,500)		(73,500)
Preferred Stock Dividends			(255)		(255)
Gain on Reacquired Preferred Stock		1			1
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,481,064
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $265				(492)	(492)
				620	620

Amortization of Pension and OPEB Deferred Costs, Net of Tax of $334					
NET INCOME			184,320		184,320
TOTAL COMPREHENSIVE INCOME					184,448
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2009	$56,584	$981,292	$649,202	$ (21,566)	$1,665,512

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$843	$728
Advances to Affiliates	160,749	-
Accounts Receivable:		
Customers	54,690	70,432
Affiliated Companies	117,941	94,205
Accrued Unbilled Revenues	11,612	19,260
Miscellaneous	2,477	1,010
Allowance for Uncollectible Accounts	(2,113)	(3,310)
Total Accounts Receivable	184,607	181,597
Fuel	67,795	67,138
Materials and Supplies	151,578	150,644
Risk Management Assets	43,120	35,012
Regulatory Asset for Under-Recovered Fuel Costs	9,965	33,066
Prepayments and Other Current Assets	166,137	66,733
TOTAL CURRENT ASSETS	784,794	534,918
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,584,836	3,534,188
Transmission	1,147,401	1,115,762
Distribution	1,339,065	1,297,482
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	785,504	703,287
Construction Work in Progress	308,039	249,020
Total Property, Plant and Equipment	7,164,845	6,899,739
Accumulated Depreciation, Depletion and Amortization	3,101,119	3,019,206
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,063,726	3,880,533
OTHER NONCURRENT ASSETS		
Regulatory Assets	495,305	455,132
Spent Nuclear Fuel and Decommissioning Trusts	1,364,442	1,259,533
Long-term Risk Management Assets	29,592	27,616
Deferred Charges and Other Noncurrent Assets	88,894	86,193
TOTAL OTHER NONCURRENT ASSETS	1,978,233	1,828,474
TOTAL ASSETS	$6,826,753	$6,243,925

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$-	$476,036
Accounts Payable:		
General	144,806	194,211
Affiliated Companies	73,395	117,589
Long-term Debt Due Within One Year – Nonaffiliated	37,544	-
Long-term Debt Due Within One Year – Affiliated	25,000	-
Risk Management Liabilities	16,011	16,079
Customer Deposits	27,493	26,809
Accrued Taxes	54,358	66,363
Obligations Under Capital Leases	30,347	43,512
Other Current Liabilities	118,519	141,160
TOTAL CURRENT LIABILITIES	527,473	