AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 30, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended June 30, 2010
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 the AEP 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 July 29, 2010
American Electric Power Company, Inc.	479,437,027
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Columbus Southern Power Company	16,410,426
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
June 30, 2010

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 or the 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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standard Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC 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.
FGD	Flue Gas Desulfurization or Scrubbers.
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.

Term	Meaning
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.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
NOx	Nitrogen oxide.
Nonutility Money Pool	AEP'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.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO 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.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.

Term	Meaning
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.
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.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility 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, customer growth and the impact of retail competition.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- 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.
- Our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process.
- 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 oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery 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 our 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.
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· Changes in utility regulation, including the implementation of ESPs and related regulation 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.
· Our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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 Conditions

Retail margins increased during the first six months of 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout AEP's service territory. In comparison to the recessionary lows of 2009, industrial sales increased 9% in the second quarter and 4% during the first six months of 2010.

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, we implemented cost reduction initiatives in the second quarter of 2010 to reduce our workforce by 11.5% and reduce other operation and maintenance spending. Achieving these goals involved identifying process improvements, streamlining organizational designs and developing other efficiencies that will deliver additional sustainable savings. In the second quarter of 2010, we recorded $293 million of expense related to these cost reduction initiatives.

Regulatory Activity

Our significant 2010 rate proceedings include:

Kentucky – In June 2010, the KPSC approved a $64 million annual increase in base rates based on a 10.5% return on common equity. New rates became effective with the first billing cycle of July 2010.

Michigan – In January 2010, I&M filed for a $63 million increase in annual base rates based on an 11.75% return on common equity. In the August billing cycle, I&M, with MPSC authorization, will implement a $44 million interim rate increase, subject to refund with interest.

Oklahoma – In July 2010, PSO filed for an $82 million increase in annual base rates, including $30 million that is currently being recovered through a rider. The requested increase is based on an 11.5% return on common equity. PSO also requested that new rates become effective no later than July 2011.

Texas – In April 2010, a settlement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on equity of 10.33%. The settlement agreement also allows SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Virginia – In July 2010, the Virginia SCC ordered an annual increase in revenues of $62 million based on a 10.53% return on equity. The order disallowed future recovery of $54 million of costs related to the Mountaineer Carbon Capture and Storage Project and allowed the deferral of approximately $25 million of incremental storm expenses incurred in 2009. As a result, APCo recorded a pretax loss of $29 million in the second quarter of 2010. In July 2010, APCo filed a petition with the Virginia SCC for reconsideration of the order as it relates to the Mountaineer Carbon

Capture and Storage Project.

West Virginia – In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. A decision from the WVPSC is expected no later than March 2011.

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Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $131 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction and its approved air and wetlands permits. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo related to the reversal of the APSC's earlier grant of a CECPN for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant Costs in Arkansas retail rates.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws.

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 SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

RESULTS OF OPERATIONS

SEGMENTS

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 transport 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 Extraordinary Loss by segment for the three and six months ended June 30, 2010 and 2009.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in millions)			
Utility Operations	$132	$327	$476	$673
AEP River Operations	(1)	1	2	12
Generation and Marketing	7	4	17	28
All Other (a)	(1)	(10)	(12)	(28)
Income Before Extraordinary Loss	$137	$322	$483	$685

(a) 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 gradually settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss in 2010 decreased $185 million compared to 2009 due to $185 million of charges incurred (net of tax) in the second quarter of 2010 related to the cost reduction initiatives.

Average basic shares outstanding increased to 479 million in 2010 from 472 million in 2009.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss in 2010 decreased $202 million compared to 2009 primarily due to $185 million of charges incurred (net of tax) in the second quarter of 2010 related to the cost reduction initiatives.

Average basic shares outstanding increased to 479 million in 2010 from 440 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 479 million as of June 30, 2010.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in millions)			
Revenues	$3,211	$3,056	$6,637	$6,323
Fuel and Purchased Power	1,110	996	2,357	2,192
Gross Margin	2,101	2,060	4,280	4,131
Depreciation and Amortization	394	388	792	761
Other Operating Expenses	1,314	993	2,354	1,987
Operating Income	393	679	1,134	1,383
Other Income, Net	42	25	85	55
Interest Expense	237	227	472	447
Income Tax Expense	66	150	271	318
Income Before Extraordinary Loss	$132	$327	$476	$673

Summary of KWH Energy Sales for Utility Operations
For the Three and Six Months Ended June 30, 2010 and 2009

	Three Months Ended June 30,		Six Months Ended June 30,	
Energy/Delivery Summary	2010	2009	2010	2009
	(in millions of KWH)			
Retail:				
Residential	12,659	12,391	30,433	28,762
Commercial	13,002	12,595	24,476	24,205
Industrial	14,662	13,400	28,044	26,922
Miscellaneous	783	771	1,495	1,490
Total Retail (a)	41,106	39,157	84,448	81,379
Wholesale	7,019	7,166	15,156	13,943
Total KWHs	48,125	46,323	99,604	95,322

(a) Includes 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 number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Six Months Ended June 30, 2010 and 2009

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
		(in degree days)		
Eastern Region				
Actual - Heating (a)	75	156	1,975	1,977
Normal - Heating (b)	170	171	1,911	1,962
Actual - Cooling (c)	434	300	434	305
Normal - Cooling (b)	289	286	293	290
Western Region				
Actual - Heating (a)	5	27	764	540
Normal - Heating (b)	21	21	595	600
Actual - Cooling (d)	866	861	886	960
Normal - Cooling (b)	757	756	815	812

(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 cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010
Income from Utility Operations Before Extraordinary Loss
(in millions)

Second Quarter of 2009	$	327
Changes in Gross Margin:		
Retail Margins		115
Off-system Sales		(12)
Transmission Revenues		(2)
Other Revenues		(60)
Total Change in Gross Margin		41
Total Expenses and Other:		
Other Operation and Maintenance		(307)
Depreciation and Amortization		(6)
Taxes Other Than Income Taxes		(14)
Interest and Investment Income		11
Carrying Costs Income		7
Allowance for Equity Funds Used During Construction		(1)
Interest Expense		(10)
Total Expenses and Other		(320)
Income Tax Expense		84
Second Quarter of 2010	$	132

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 $115 million primarily due to the following:
  - A $22 million increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia, a $13 million increase in the recovery of advanced metering costs in Texas and a $13 million net increase in rates in our other jurisdictions. These increases in retail margins had corresponding offsets of $26 million related to cost recovery riders/trackers that were recognized in the other gross margin/other expense line items below.
  - A $34 million increase in weather-related usage primarily due to a 45% increase in cooling degree days in our eastern region.
  - A $20 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.

  These increases were partially offset by:

  ·

A $9 million decrease due to the termination of an I&M unit power agreement.

- Margins from Off-system Sales decreased $12 million primarily due to lower trading and marketing margins, partially offset by higher physical sales volumes.
- Other Revenues decreased $60 million primarily due to the Cook Plant accidental outage insurance proceeds of $46 million, which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $20 million in the second quarter of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

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

- Other Operation and Maintenance expenses increased $307 million primarily due to the following:
  - A $278 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
  - A $54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.
  - A $27 million increase in demand side management, energy efficiency, vegetation management programs and other costs which have associated cost recovery riders/trackers that were recognized in retail revenues.

  These increases were partially offset by:
  - A $25 million decrease due to the deferral of 2009 storm costs as allowed by the Virginia SCC.
  - A $14 million decrease in plant outage and other plant operating and maintenance expenses.
- Depreciation and Amortization increased $6 million primarily due to new environmental improvements placed in service and other increases in depreciable property balances.
- Taxes Other Than Income Taxes increased $14 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
- Interest and Investment Income increased $11 million primarily due to the second quarter 2009 write-off of other-than-temporary losses related to equity investments made by EIS.
- Carrying Costs Income increased $7 million primarily due to increased environmental deferrals in Virginia and a higher under-recovered fuel balance for OPCo.
- Interest Expense increased $10 million primarily due to an increase in long-term debt.
- Income Tax Expense decreased $84 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010
Income from Utility Operations Before Extraordinary Loss
(in millions)

Six Months Ended June 30, 2009	$	673
Changes in Gross Margin:		
Retail Margins		283
Off-system Sales		1
Transmission Revenues		8
Other Revenues		(143)
Total Change in Gross Margin		149
Total Expenses and Other:		
Other Operation and Maintenance		(344)
Depreciation and Amortization		(31)
Taxes Other Than Income Taxes		(23)
Interest and Investment Income		8
Carrying Costs Income		12
Allowance for Equity Funds Used During Construction		7
Interest Expense		(25)
Equity Earnings of Unconsolidated Subsidiaries		3
Total Expenses and Other		(393)
Income Tax Expense		47
Six Months Ended June 30, 2010	$	476

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 $283 million primarily due to the following:
  - A $75 million increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia, a $25 million increase in the recovery of advanced metering costs in Texas, a $19 million rate increase in Oklahoma, a $17 million net rate increase for I&M, a $13 million net increase in rates for SWEPCo and a $27 million net increase in rates in our other jurisdictions. These increases in retail margins had corresponding offsets of $64 million related to cost recovery riders/trackers that were recognized in the other gross margin/other expense line items below.
  - A $71 million increase in weather-related usage primarily due to a 43% increase in cooling degree days in our eastern region and a 41% increase in heating degree days in our western region.
  - A $42 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Unit 1 shutdown. This increase

in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.

These increases were partially offset by:

- A $17 million decrease due to the termination of an I&M unit power agreement.

- Transmission Revenues increased $8 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- Other Revenues decreased $143 million primarily due to the Cook Plant accidental outage insurance proceeds of $99 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $42 million in the first six months of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above. Other Revenues also decreased due to lower gains on sales of emission allowances of $23 million.

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

- Other Operation and Maintenance expenses increased $344 million primarily due to the following:
  - A $278 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
  - A $72 million increase in demand side management, energy efficiency, vegetation management programs and other costs which have associated cost recovery riders/trackers that were recognized in retail revenues.
  - A $54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.

  These increases were partially offset by:
  - A $59 million decrease in storm expenses including the deferral of $25 million of 2009 storm costs as allowed by the Virginia SCC.
- Depreciation and Amortization increased $31 million primarily due to new environmental improvements placed in service and other increases in depreciable property balances.
- Taxes Other Than Income Taxes increased $23 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010 and higher franchise and property taxes.
- Interest and Investment Income increased $8 million primarily due to the second quarter 2009 write-off of other-than-temporary losses related to equity investments made by EIS.
- Carrying Costs Income increased $12 million primarily due to increased environmental deferrals in Virginia and a higher under-recovered fuel balance for OPCo.
- Allowance for Equity Funds Used During Construction increased $7 million related to construction projects 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 the second quarter of 2009.
- Interest Expense increased $25 million primarily due to an increase in long-term debt and a decrease in the debt component of AFUDC due to lower CWIP balances at APCo, CSPCo and OPCo.
- Income Tax Expense decreased $47 million primarily due to a decrease in pretax book income, partially offset by the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

AEP RIVER OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss from our AEP River Operations segment decreased from income of $1 million in 2009 to a loss of $1 million in 2010 primarily due to expenses related to the cost reduction initiatives, increased interest expense on new long-term debt and increased lease expense on new barge leases.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss from our AEP River Operations segment decreased from $12 million in 2009 to $2 million in 2010 primarily due to reduced grain loadings, higher fuel and other operating expenses, expenses related to the cost reduction initiatives, interest expense on increased long-term debt, increased lease expense on new barge leases and a gain on the sale of two older towboats in 2009.

GENERATION AND MARKETING

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss from our Generation and Marketing segment increased from $4 million in 2009 to $7 million in 2010 primarily due to favorable marketing contracts in ERCOT and increased income from our wind farm operations.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss from our Generation and Marketing segment decreased from $28 million in 2009 to $17 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities partially offset by improved plant performance, hedging activities on our generation assets and increased income from our wind farm operations.

ALL OTHER

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss from All Other increased from a loss of $10 million in 2009 to a loss of $1 million in 2010 primarily due to $16 million in pretax gains ($10 million, net of tax) on the sale of our remaining 138,000 shares of Intercontinental Exchange, Inc. (ICE) in the second quarter of 2010.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss from All Other increased from a loss of $28 million in 2009 to a loss of $12 million in 2010 due to $16 million in pretax gains ($10 million, net of tax) on the sale of our remaining 138,000 shares of ICE in the second quarter of 2010.

AEP SYSTEM INCOME TAXES

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Tax Expense decreased $83 million in comparison to 2009 primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Tax Expense decreased $55 million in comparison to 2009 primarily due to a decrease in pretax book income, partially offset by the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

FINANCIAL CONDITION

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

DEBT AND EQUITY CAPITALIZATION

	June 30, 2010			December 31, 2009		
			($ in millions)			
Long-term Debt, including amounts due within one year	$17,348	53.9	%	$17,498	56.8	%
Short-term Debt	1,473	4.6		126	0.4	
Total Debt	18,821	58.5		17,624	57.2	
Preferred Stock of Subsidiaries	60	0.2		61	0.2	
AEP Common Equity	13,269	41.3		13,140	42.6	
Noncontrolling Interests	1	-		-	-	
Total Debt and Equity Capitalization	$32,151	100.0	%	$30,825	100.0	%

Our ratio of debt-to-total capital increased from 57.2% in 2009 to 58.5% in 2010 primarily due to an increase in short-term debt of $677 million as a result of a change in an accounting standard applicable to our sale of receivables agreement and an increase of $668 million in commercial paper outstanding.

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 June 30, 2010, we had $3.4 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.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At June 30, 2010, our available liquidity was approximately $2.9 billion as illustrated in the table below:

			Amount (in millions)	Maturity
Commercial Paper Backup:				
	Revolving Credit Facility	$	1,454	April 2012
	Revolving Credit Facility		1,500	June 2013
Revolving Credit Facility			478	April 2011
Total			3,432	
Cash and Cash Equivalents			838	
Total Liquidity Sources			4,270	
Less:	AEP Commercial Paper Outstanding		787	
	Letters of Credit Issued		626	
Net Available Liquidity		$	2,857	

We have credit facilities totaling $3.4 billion, of which two $1.5 billion credit facilities support our commercial paper program. One of the $1.5 billion credit facilities allows for the issuance of up to $750 million as letters of credit. In June 2010, we canceled a facility that was scheduled to mature in March 2011. We also entered a new $1.5 billion credit facility in June 2010, which matures in 2013, that allows for the issuance of up to $600 million as letters of credit. In June 2010, we reduced the credit facility that matures in April 2011 from $627 million to $478 million which can be utilized for letters of credit or draws.

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. The maximum amount of commercial paper outstanding during 2010 was $802 million. The weighted-average interest rate for our commercial paper during 2010 was 0.42%.

Securitized Accounts Receivables

In July 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

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Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined in our revolving credit agreements. At June 30, 2010, this contractually-defined percentage was 54.8%. Nonperformance under these covenants could result in an event of default under these credit agreements. At June 30, 2010, 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 June 30, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.42 per share in July 2010. 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. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. We have the option to defer interest payments on the AEP Junior Subordinated Debentures 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 access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs.

CASH FLOW

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

	Six Months Ended June 30,	
	2010	2009
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 490	$ 411
Net Cash Flows from Operating Activities	582	857
Net Cash Flows Used for Investing Activities	(992)	(1,478)
Net Cash Flows from Financing Activities	758	568

Net Increase (Decrease) in Cash and Cash Equivalents	348	(53)
Cash and Cash Equivalents at End of Period	$ 838	$ 358

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Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Six Months Ended June 30, 2010	2009
	(in millions)	
Net Income	$ 483	$ 680
Depreciation and Amortization	813	779
Other	(714)	(602)
Net Cash Flows from Operating Activities	$ 582	$ 857

Net Cash Flows from Operating Activities were $582 million in 2010 consisting primarily of Net Income of $483 million and $813 million of noncash Depreciation and Amortization. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. Other changes 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. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a change in tax accounting method and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Operating Activities were $857 million in 2009 consisting primarily of Net Income of $680 million and $779 million of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity as the result of the economic slowdown and an increase in under-recovered fuel primarily due to the deferral of fuel costs in Ohio as a fuel clause was reactivated in 2009.

Investing Activities

	Six Months Ended June 30, 2010	2009
	(in millions)	
Construction Expenditures	$ (1,104)	$ (1,547)
Acquisitions of Nuclear Fuel	(41)	(152)
Proceeds from Sales of Assets	147	240
Other	6	(19)
Net Cash Flows Used for Investing Activities	$ (992)	$ (1,478)

Net Cash Flows Used for Investing Activities were $992 million in 2010 primarily due to Construction Expenditures for new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2010 include $135 million for sales of Texas transmission assets to ETT.

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

Financing Activities

	Six Months Ended June 30,	
	2010	2009
	(in millions)	
Issuance of Common Stock, Net	$ 42	$ 1,688
Issuance/Retirement of Debt, Net	1,166	(711)
Dividends Paid on Common Stock	(399)	(364)
Other	(51)	(45)
Net Cash Flows from Financing Activities	$ 758	$ 568

Net Cash Flows from Financing Activities were $758 million in 2010. Our net debt issuances were $1.2 billion. The net issuances included issuances of $884 million of notes and $287 million of pollution control bonds, a $668 million increase in commercial paper outstanding and retirements of $1 billion of senior unsecured notes, $86 million of securitization bonds and $183 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for “Transfers and Servicing” related to our sale of receivables agreement. We paid common stock dividends of $399 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2009 were $568 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 $711 million. These retirements included a repayment of $1.75 billion outstanding under our credit facilities primarily from the proceeds of our common stock issuance and issuances of $955 million of senior unsecured notes and $135 million of pollution control bonds.

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading 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 transfers of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

	June 30, 2010	December 31, 2009
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ -	$ 631
Rockport Plant Unit 2 Future Minimum Lease Payments	1,846	1,920
Railcars Maximum Potential Loss From Lease Agreement	25	25

Effective January 1, 2010, we record the receivables and debt related to AEP Credit on our Condensed Consolidated Balance Sheet. 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 2009 Annual Report.

SUMMARY OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2009 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” 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 2009 Annual Report. The 2009 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 2009 Annual Report, but may have a material impact on our future net income, cash flows and financial condition.

REGULATORY ISSUES

Ohio Electric Security Plan Filings

During 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs which established rates through 2011. The order also limits rate 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. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. CSPCo and OPCo will file their significantly excessive earnings test with the PUCO by their September 2010 deadline. CSPCo and OPCo are unable to determine whether they will be required to return any of their ESP revenues to customers. See "Ohio Electric Security Plan Filings" section of Note 3.

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. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

Texas Restructuring Appeals

Pursuant to PUCT restructuring 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 also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See "Texas Restructuring Appeals" section of Note 3.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, jointly constructed a CO2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO2. In APCo's July 2009 Virginia base rate filing and APCo's May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a pretax write-off of approximately $54 million in the second quarter of 2010. In response to the order, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. Through June 30, 2010, APCo has recorded a noncurrent regulatory asset of $58 million consisting of $38 million in project costs and $20 million in asset retirement costs. If APCo cannot recover its remaining investments in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition. See "Mountaineer Carbon Capture and Storage Project" section of Note 3.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $131 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $131 million for transmission, excluding AFUDC. Notices of appeal are outstanding at the Arkansas Court of Appeals and the Circuit Court of Hempstead County, Arkansas. Matters are also outstanding at the LPSC, the Texas Court of Appeals and the Federal District Court for the Western District of Arkansas. See "Turk Plant" section of Note 3.

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 resolution will be or the timing and amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss 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 2009 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.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We anticipate making additional investments and operational changes. The most significant sources are the existing and anticipated CAA requirements to reduce emissions of SO2, NOx, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO2 emissions to address concerns about global climate change. See a complete discussion of these matters in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 Annual Report.

Clean Air Act Transport Rule (Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace the Clean Air Interstate Rule (CAIR) that would impose new and more stringent requirements to control SO2 and NOx emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO2 and/or NOx. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NOx program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NOx programs and an annual SO2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately 1 million tons per year more SO2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces emissions by an additional 800,000 tons per year. The SO2 and NOx programs rely on newly-created allowances rather than relying on the CAIR NOx allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and stringency of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers, as these features could accelerate unit retirements, increase capital requirements, constrain operations and decrease reliability. Comments on the proposed rule will be due within 60 days after publication in the Federal Register.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at our coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities. We are currently studying the potential costs associated with this proposal and expect that it will impose significant costs. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, these costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

While comprehensive economy-wide regulation of CO2 emissions might be achieved through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO2 emissions from stationary sources will be subject to regulation under the CAA beginning in January 2011 at the earliest and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs. The Federal EPA is reconsidering whether to include CO2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units.

Our fossil fuel-fired generating units are very large sources of CO2 emissions. If substantial CO2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO2 emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 4.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

For detailed information on global warming and the actions we are taking to address potential impacts, see Part I of the 2009 Form 10-K under the headings entitled "Business – General – Environmental and Other Matters – Global Warming" and "Management's Financial Discussion and Analysis of Results of Operations."

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 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.

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2010

We adopted ASU 2009-16 "Transfers and Servicing" effective January 1, 2010. The adoption of this standard resulted in AEP Credit's transfers of receivables being accounted for as financings with the receivables and short-term debt recorded on our balance sheet.

We adopted the prospective provisions of ASU 2009-17 "Consolidations" effective January 1, 2010. We no longer consolidate DHLC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, 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, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. 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.

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 are 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 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 table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2009:

MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2010
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$ 134	$ 147	$ (3)	$ 278
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(39)	(9)	3	(45)
Fair Value of New Contracts at Inception When Entered During the Period (a)	8	8	-	16
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	(1)	-	-	(1)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	(2)	(2)	-	(4)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	10	6	-	16
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	22	-	-	22
Total MTM Risk Management Contract Net Assets at June 30, 2010	$ 132	$ 150	$ -	282
Cash Flow Hedge Contracts				(2)
Fair Value Hedge Contracts				4
Collateral Deposits				77
Total MTM Derivative Contract Net Assets at June 30, 2010				$ 361

(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) Reflects changes in methodology in calculating the credit and discounting liability fair value adjustments.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d) 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.

See Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

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 Investors Service, Standard & Poor's 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 have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of June 30, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.0%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of June 30, 2010, 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	$ 717	$ 46	$ 671	1	$ 152
Split Rating	4	-	4	1	4
Noninvestment Grade	3	1	2	4	2
No External Ratings:					
Internal Investment Grade	145	-	145	3	100
Internal Noninvestment Grade	82	11	71	3	63
Total as of June 30, 2010	$ 951	$ 58	$ 893	12	$ 321
Total as of December 31, 2009	$ 846	$ 58	$ 788	12	$ 317

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of June 30, 2010, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

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

VaR Model

Six Months Ended June 30, 2010 (in millions)				Twelve Months Ended December 31, 2009 (in millions)			
End	High	Average	Low	End	High	Average	Low
$1	$2	$1	$-	$1	$2	$1	$-

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

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

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of June 30, 2010 and December 31, 2009, the estimated EaR on our debt portfolio for the following twelve months was $3 million and $4 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2010 and 2009
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2010	2009	2010	2009
REVENUES				
Utility Operations	$3,186	$3,035	$6,592	$6,302
Other Revenues	174	167	337	358
TOTAL REVENUES	3,360	3,202	6,929	6,660
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	895	764	1,909	1,693
Purchased Electricity for Resale	227	258	465	553
Other Operation	994	638	1,667	1,248
Maintenance	243	271	514	566
Depreciation and Amortization	405	397	813	779
Taxes Other Than Income Taxes	202	192	409	389
TOTAL EXPENSES	2,966	2,520	5,777	5,228
OPERATING INCOME	394	682	1,152	1,432
Other Income (Expense):				
Interest and Investment Income (Loss)	18	(5)	21	-
Carrying Costs Income	19	12	33	21
Allowance for Equity Funds Used During Construction	19	20	43	36
Interest Expense	(249)	(240)	(499)	(478)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	201	469	750	1,011
Income Tax Expense	65	148	272	327
Equity Earnings of Unconsolidated Subsidiaries	1	1	5	1
INCOME BEFORE EXTRAORDINARY LOSS	137	322	483	685
EXTRAORDINARY LOSS, NET OF TAX	-	(5)	-	(5)
NET INCOME	137	317	483	680
Less: Net Income Attributable to Noncontrolling Interests	1	1	2	3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	136	316	481	677

Less: Preferred Stock Dividend Requirements of Subsidiaries	-	-	1	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$136	$316	$480	$676
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	479,050,774	472,220,041	478,741,871	439,703,968
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Extraordinary Loss	$0.28	$0.68	$1.00	$1.55
Extraordinary Loss, Net of Tax	-	(0.01)	-	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.28	$0.67	$1.00	$1.54
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	479,176,543	472,222,817	479,012,304	439,983,030
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
Income Before Extraordinary Loss	$0.28	$0.68	$1.00	$1.55
Extraordinary Loss, Net of Tax	-	(0.01)	-	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.28	$0.67	$1.00	$1.54
CASH DIVIDENDS PAID PER SHARE	$0.42	$0.41	$0.83	$0.82

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2010 and 2009
(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, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	71	460	1,278				1,738
Common Stock Dividends				(363)		(3)	(366)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			(50)			1	(49)
SUBTOTAL – EQUITY							12,032
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $9					17		17
Securities Available for Sale, Net of Tax of $5					9		9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $14					25		25
NET INCOME				677		3	680
TOTAL COMPREHENSIVE INCOME							731
TOTAL EQUITY – JUNE 30, 2009	497	$ 3,231	$ 5,755	$ 4,160	$ (401)	$ 18	$ 12,763
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
	2	9	34				43

Issuance of Common Stock							
Common Stock Dividends				(398)		(1)	(399)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			2				2
SUBTOTAL – EQUITY							12,785
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $1					2		2
Securities Available for Sale, Net of Tax of $6					(11)		(11)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $6					11		11
NET INCOME				481		2	483
TOTAL COMPREHENSIVE INCOME							485
TOTAL EQUITY – JUNE 30, 2010	500	$ 3,248	$ 5,860	$ 4,533	$ (372)	$ 1	$ 13,270

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2010 and December 31, 2009
(in millions)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$838	$490
Other Temporary Investments	298	363
Accounts Receivable:		
Customers	651	492
Accrued Unbilled Revenues	115	503
Pledged Accounts Receivable - AEP Credit	1,011	-
Miscellaneous	114	92
Allowance for Uncollectible Accounts	(44)	(37)
Total Accounts Receivable	1,847	1,050
Fuel	984	1,075
Materials and Supplies	593	586
Risk Management Assets	250	260
Accrued Tax Benefits	653	547
Regulatory Asset for Under-Recovered Fuel Costs	104	85
Margin Deposits	74	89
Prepayments and Other Current Assets	152	211
TOTAL CURRENT ASSETS	5,793	4,756
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	23,930	23,045
Transmission	8,420	8,315
Distribution	13,799	13,549
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,820	3,744
Construction Work in Progress	2,431	3,031
Total Property, Plant and Equipment	52,400	51,684
Accumulated Depreciation and Amortization	17,682	17,340
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	34,718	34,344
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,732	4,595
Securitized Transition Assets	1,834	1,896
Spent Nuclear Fuel and Decommissioning Trusts	1,391	1,392
Goodwill	76	76
Long-term Risk Management Assets	408	343
Deferred Charges and Other Noncurrent Assets	985	946
TOTAL OTHER NONCURRENT ASSETS	9,426	9,248
TOTAL ASSETS	$49,937	$48,348

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 863	$ 1,158
Short-term Debt:		
General	796	126
Securitized Debt for Receivables - AEP Credit	677	-
Total Short-term Debt	1,473	126
Long-term Debt Due Within One Year	1,043	1,741
Risk Management Liabilities	120	120
Customer Deposits	266	256
Accrued Taxes	570	632
Accrued Interest	284	287
Regulatory Liability for Over-Recovered Fuel Costs	27	76
Other Current Liabilities	1,132	931
TOTAL CURRENT LIABILITIES	5,778	5,327
NONCURRENT LIABILITIES		
Long-term Debt	16,305	15,757
Long-term Risk Management Liabilities	177	128
Deferred Income Taxes	6,671	6,420
Regulatory Liabilities and Deferred Investment Tax Credits	3,017	2,909
Asset Retirement Obligations	1,280	1,254
Employee Benefits and Pension Obligations	2,107	2,189
Deferred Credits and Other Noncurrent Liabilities	1,272	1,163
TOTAL NONCURRENT LIABILITIES	30,829	29,820
TOTAL LIABILITIES	36,607	35,147
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	61
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2010	2009		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	499,655,121	498,333,265		
(20,278,858 shares were held in treasury at June 30, 2010 and December 31, 2009)			3,248	3,239
Paid-in Capital			5,860	5,824
Retained Earnings			4,533	4,451

Accumulated Other Comprehensive Income (Loss)	(372)	(374)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,269	13,140
Noncontrolling Interests	1	-
TOTAL EQUITY	13,270	13,140
TOTAL LIABILITIES AND EQUITY	$ 49,937	$ 48,348

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2010 and 2009
(in millions)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$483	$680
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	813	779
Deferred Income Taxes	212	360
Extraordinary Loss, Net of Tax	-	5
Carrying Costs Income	(33)	(21)
Allowance for Equity Funds Used During Construction	(43)	(36)
Mark-to-Market of Risk Management Contracts	4	(83)
Amortization of Nuclear Fuel	69	25
Property Taxes	54	38
Fuel Over/Under-Recovery, Net	(181)	(246)
Change in Other Noncurrent Assets	(21)	(11)
Change in Other Noncurrent Liabilities	65	84
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(802)	29
Fuel, Materials and Supplies	71	(313)
Margin Deposits	15	(49)
Accounts Payable	(168)	18
Customer Deposits	9	17
Accrued Taxes, Net	(164)	(110)
Accrued Interest	(3)	3
Other Current Assets	51	(25)
Other Current Liabilities	151	(287)
Net Cash Flows from Operating Activities	582	857
INVESTING ACTIVITIES		
Construction Expenditures	(1,104)	(1,547)
Change in Other Temporary Investments, Net	31	43
Purchases of Investment Securities	(838)	(443)
Sales of Investment Securities	849	411
Acquisitions of Nuclear Fuel	(41)	(152)
Acquisitions of Assets	(12)	(11)
Proceeds from Sales of Assets	147	240
Other Investing Activities	(24)	(19)
Net Cash Flows Used for Investing Activities	(992)	(1,478)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	42	1,688
Issuance of Long-term Debt	1,161	1,075
Borrowings from Revolving Credit Facilities	50	59
Change in Short-term Debt, Net	1,345	328

Retirement of Long-term Debt	(1,341)	(372)
Repayments to Revolving Credit Facilities	(49)	(1,801)
Principal Payments for Capital Lease Obligations	(49)	(42)
Dividends Paid on Common Stock	(399)	(364)
Dividends Paid on Cumulative Preferred Stock	(1)	(1)
Other Financing Activities	(1)	(2)
Net Cash Flows from Financing Activities	758	568
Net Increase (Decrease) in Cash and Cash Equivalents	348	(53)
Cash and Cash Equivalents at Beginning of Period	490	411
Cash and Cash Equivalents at End of Period	$838	$358
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$487	$495
Net Cash Paid for Income Taxes	174	27
Noncash Acquisitions Under Capital Leases	176	17
Construction Expenditures Included in Accounts Payable at June 30,	205	270

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 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 six months ended June 30, 2010 is not necessarily indicative of results that may be expected for the year ending December 31, 2010. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2009 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 26, 2010.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, 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. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are the primary beneficiary of Sabine, DCC Fuel LLC, DCC Fuel II LLC, AEP Credit, AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLC as defined by the new accounting guidance for "Variable Interest Entities." In addition, we have not provided material financial or other support to Sabine, DCC Fuel, DCC Fuel II, AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series) and DHLC.

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. In addition, SWEPCo determines how much coal will be mined for each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended June 30, 2010 and 2009 were $30 million and $25 million, respectively, and for the six months ended June 30, 2010 and 2009 were $73 million and

$61 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Condensed Consolidated Balance Sheets.

EIS has multiple protected cells. 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 our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the three months ended June 30, 2010 and 2009 were $254 thousand and $132 thousand, respectively, and for the six months ended June 30, 2010 and 2009 were $18 million and $17 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Condensed Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. DCC Fuel LLC and DCC Fuel II LLC (collectively DCC) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the leases are made semi-annually and began in April 2010. Payments on the leases for the three months ended June 30, 2010 were $22 million and for the six months ended June 30, 2010 were $22 million. No payments were made to DCC in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 and 54 month lease term, respectively. Based on our control of DCC, management concluded that I&M is the primary beneficiary and is required to consolidate DCC. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC's assets and liabilities on our Condensed Consolidated Balance Sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables sold for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our Condensed Consolidated Balance Sheets. See the "ASU 2009-17 'Consolidation' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010. Also, see "Sale of Receivables – AEP Credit" section of Note 14 in the 2009 Annual Report for further information.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO 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 shared control of DHLC's operations, management concluded as of January 1, 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC. SWEPCo's total billings from DHLC for the three months ended June 30, 2010 and 2009 were $13 million and $8 million, respectively, and for the six months ended June 30, 2010 and 2009 were $26 million and $18 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on our Condensed Consolidated Balance Sheet at December 31, 2009 as well as our investment and maximum exposure as of June 30, 2010. As of January 1, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC, (collectively Transition Funding) were formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.9 billion at June 30, 2010 and are included in current and long-term debt on the Condensed Consolidated Balance Sheets. Transition Funding has securitized transition assets of $1.8 billion at June 30, 2010, which are presented separately on the face of the Condensed Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition asset and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
June 30, 2010
(in millions)

	SWEPCo Sabine	I&M DCC	Protected Cell of EIS	AEP Credit
ASSETS				
Current Assets	$ 48	$ 76	$ 140	$ 984
Net Property, Plant and Equipment	144	141	-	-
Other Noncurrent Assets	34	93	2	10
Total Assets	$ 226	$ 310	$ 142	$ 994
LIABILITIES AND EQUITY				
Current Liabilities	$ 31	$ 63	$ 34	$ 906
Noncurrent Liabilities	194	247	95	1
Equity	1	-	13	87
Total Liabilities and Equity	$ 226	$ 310	$ 142	$ 994

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	I&M DCC	Protected Cell of EIS
ASSETS				
Current Assets	$ 51	$ 8	$ 47	$ 130
Net Property, Plant and Equipment	149	44	89	-
Other Noncurrent Assets	35	11	57	2
Total Assets	$ 235	$ 63	$ 193	$ 132
LIABILITIES AND EQUITY				
Current Liabilities	$ 36	$ 17	$ 39	$ 36
Noncurrent Liabilities	199	38	154	74
Equity	-	8	-	22
Total Liabilities and Equity	$ 235	$ 63	$ 193	$ 132

Our investment in DHLC was:

	June 30, 2010	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)	
Capital Contribution from SWEPCo	$ 7	$ 7
Retained Earnings	1	1
SWEPCo's Guarantee of Debt	-	48
Total Investment in DHLC	$ 8	$ 56

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" nor "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	June 30, 2010		December 31, 2009	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 14	$ 14	$ 13	$ 13
Retained Earnings	4	4	3	3
Total Investment in PATH-WV	$ 18	$ 18	$ 16	$ 16

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

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

	Three Months Ended June 30,			
	2010		2009	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 136		$ 316	
Weighted Average Number of Basic Shares Outstanding	479.1	$ 0.28	472.2	$ 0.67
Weighted Average Dilutive Effect of:				
Restricted Stock Units	0.1	-	-	-
Weighted Average Number of Diluted Shares Outstanding	479.2	$ 0.28	472.2	$ 0.67

	Six Months Ended June 30,			
	2010		2009	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 480		$ 676	
Weighted Average Number of Basic Shares Outstanding	478.7	$ 1.00	439.7	$ 1.54
Weighted Average Dilutive Effect of:				
Performance Share Units	0.1	-	0.3	-
Stock Options	0.1	-	-	-
Restricted Stock Units	0.1	-	-	-
Weighted Average Number of Diluted Shares Outstanding	479.0	$ 1.00	440.0	$ 1.54

The assumed conversion of stock options does not affect net earnings for purposes of calculating diluted earnings per share.

Options to purchase 432,366 and 1,123,869 shares of common stock were outstanding at June 30, 2010 and 2009, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive. AEP's average stock price was $33.04 per share and its exercise prices for non-dilutive stock options outstanding ranged from $38.65 to $49.00 per share.

Supplementary Information

Related Party Transactions	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in millions)			
AEP Consolidated Revenues – Utility Operations:				
Ohio Valley Electric Corporation (43.47% owned) (a)	$ (11)	$ -	$ (20)	$ -
AEP Consolidated Revenues – Other Revenues:				
Ohio Valley Electric Corporation – Barging and Other				
Transportation Services (43.47% Owned)	8	7	16	16
AEP Consolidated Expenses – Purchased Energy for Resale:				
Ohio Valley Electric Corporation (43.47% Owned) (b)	80	72	157	142

(a) In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales through June 2010.

(b) In January 2010, the AEP Power Pool began purchasing power from OVEC to serve retail sales through June 2010. The total amount reported includes $4 million and $10 million related to the new agreement for the three and six months ended June 30, 2010, respectively.

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

Amounts Attributable to AEP Common Shareholders	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in millions)			
Income Before Extraordinary Loss	$ 136	$ 321	$ 480	$ 681
Extraordinary Loss, Net of Tax	-	(5)	-	(5)
Net Income	$ 136	$ 316	$ 480	$ 676

Adjustments to Reported Cash Flows

In the Financing Activities section of our Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2009, we corrected the presentation of borrowings on our lines of credit of $59 million from Change in Short-term Debt, Net to Borrowings from Revolving Credit Facilities. We also corrected the presentation of repayments on our lines of credit of $1.8 billion for the six months ended June 30, 2009 to Repayments to Revolving Credit Facilities from Change in Short-term Debt, Net. The correction to present borrowings and repayments on our lines of credit on a gross basis was not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or net cash flows from financing activities.

Adjustments to Securitized Accounts Receivable Disclosure

In the “Securitized Accounts Receivable – AEP Credit” section of Note 11, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders’ equity, financial position or cash flows.

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 that impact our financial statements.

Pronouncements Adopted During 2010

The following standards were effective during the first six months of 2010. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2009-16 "Transfers and Servicing" (ASU 2009-16)

In 2009, the FASB issued ASU 2009-16 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.

We adopted ASU 2009-16 effective January 1, 2010. AEP Credit transfers an interest in receivables it acquires from certain of its affiliates to bank conduits and receives cash. As of December 31, 2009, AEP Credit owed $656 million to bank conduits related to receivable sales outstanding. Upon adoption of ASU 2009-16, future transactions do not constitute a sale of receivables and are accounted for as financings. Effective January 2010, we record the receivables and related debt on our Condensed Consolidated Balance Sheet.

ASU 2009-17 "Consolidations" (ASU 2009-17)

In 2009, the FASB issued ASU 2009-17 amending the analysis an entity must perform to determine if it has a controlling financial interest in a VIE. In addition to presentation and disclosure guidance, ASU 2009-17 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.

We adopted the prospective provisions of ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, we report DHLC using the equity method of accounting.

This standard increased our disclosure requirements for AEP Credit, a wholly-owned consolidated subsidiary. See "Variable Interest Entities" section of Note 1 for further discussion.

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 return 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 2009 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2009 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 2010 and updates the 2009 Annual Report.

Regulatory Assets Not Yet Being Recovered

	June 30, 2010	December 31, 2009
	(in millions)	
Noncurrent Regulatory Assets (excluding fuel)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Earning a Return		
Customer Choice Deferrals - CSPCo, OPCo	$ 58	$ 57
Storm Related Costs - CSPCo, OPCo, TCC	50	49
Line Extension Carrying Costs - CSPCo, OPCo	49	43
Acquisition of Monongahela Power - CSPCo	11	10
Regulatory Assets Currently Not Earning a Return		
Mountaineer Carbon Capture and Storage Project - APCo	58	111
Environmental Rate Adjustment Clause - APCo	43	25
Storm Related Costs - APCo, PSO	41	-
Transmission Rate Adjustment Clause - APCo	21	26
Special Rate Mechanism for Century Aluminum - APCo	13	12
Deferred Wind Power Costs - APCo	12	5
Storm Related Costs - KPCo	- (a)	24
Peak Demand Reduction/Energy Efficiency - CSPCo, OPCo	- (a)	8
Total Regulatory Assets Not Yet Being Recovered	$ 356	$ 370

(a) Recovery of regulatory asset was granted during 2010.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved CSPCo’s and OPCo’s ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limits annual rate 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. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected 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 is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the "2009 Fuel Adjustment Clause Audit" section below. The order allows CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at CSPCo's and OPCo's weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. Management expects to recover the CSPCo FAC deferral during 2010. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the "Ormet Interim Arrangement" section below. The FAC deferrals as of June 30, 2010 were $5 million and $388 million for CSPCo and OPCo, respectively, excluding $1 million and $18 million, respectively, of unrecognized equity carrying costs.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio group filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMARTSM and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In April 2010, the Industrial Energy Users-Ohio group filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In 2009, the PUCO convened a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET). Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. The PUCO heard arguments related to various SEET issues including the treatment of the FAC deferrals. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets until they are collected, even assuming there are significantly excessive earnings in that year. In June 2010, the PUCO issued an order resolving some of the SEET issues. The PUCO determined that the earnings of CSPCo and OPCo shall be calculated on an individual company basis and not on a combined CSPCo/OPCo basis. The PUCO ruled that many issues including the treatment of deferrals and off-system sales should be determined on a case-by-case basis. The PUCO's decision on the SEET methodology is not expected to be finalized until after the SEET filings are made by CSPCo and OPCo related to 2009 earnings and the PUCO issues an order thereon. CSPCo and OPCo will file their significantly excessive earnings tests with the PUCO by their September 2010 deadlines. CSPCo and OPCo are unable to determine whether they will be required to return any of their ESP revenues to customers.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report of the FAC audit to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million will reduce fuel expense in 2009 and 2010. If the PUCO orders any portion of the $58 million previously recognized gains be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim

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arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had $30 million and $34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges but excluding $1 million and $1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP Orders.

As of June 30, 2010, CSPCo and OPCo have incurred $32 million and $23 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $16 million and $12 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $16 million and $11 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. CSPCo's and OPCo's proposed initial rider would recover 2009 carrying costs of $29 million and $37 million, respectively, through December 2011. In July 2010, CSPCo and OPCo filed an updated position to its application which reduced its original rider application amount to recover $27 million and $35 million, respectively, through December 2011. If approved, the implementation of the rider will likely not impact cash flows, but will increase the ESP phase-in plan deferrals associated with the FAC since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through June 30, 2010, CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

Ohio Energy Efficiency & Demand Response Program Rider

In November 2009, CSPCo and OPCo filed an application with the PUCO to implement energy efficiency and demand response programs as part of Senate Bill 221, which requires investor-owned utilities to create programs to help customers conserve and reduce demand for electricity. Simultaneous with the filing, a stipulation agreement was filed with the PUCO agreeing to terms consistent with the filed application. In May 2010, the PUCO issued an order adopting the stipulation, with minor modification, and authorized CSPCo and OPCo to implement a new rider rate effective with the first billing cycle in June 2010. The rider rates are estimated to increase CSPCo's and OPCo's revenues by $81 million and $86 million, respectively, over the period from June 2010 through December 2011. CSPCo's and OPCo's revenue increases include $79 million and $83 million, respectively, for program costs and $2 million and $3 million, respectively, for net lost distribution revenues and shared savings.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $131 million for transmission, excluding AFUDC. SWEPCo’s share is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $131 million for transmission, excluding AFUDC. As of June 30, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $855 million of expenditures (including AFUDC and capitalized interest of $106 million and related transmission costs of $46 million). As of June 30, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $425 million (including related transmission costs of $7 million). SWEPCo’s share of the contractual construction commitments is $312 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of June 30, 2010, of approximately $121 million (including related transmission cancellation fees of $1 million). SWEPCo’s share of the contractual construction cancellation fees would be approximately $89 million.

Discussed below are the outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC’s grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC’s procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. In June 2010, the Arkansas

Supreme Court denied motions for rehearing filed by the APSC and SWEPCo. Therefore, SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club petitioned the LPSC to begin an investigation into the construction of the Turk Plant which was rejected by the LPSC in November 2009. In December 2009, the Sierra Club refiled its petition as a stand alone complaint proceeding. In February 2010, SWEPCo filed a motion to dismiss and denied the allegations in the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas.

The wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In February 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. In May 2010, parties filed with the Federal District Court for the Western District of Arkansas for a preliminary injunction to halt construction and for a temporary restraining order.

In January 2009, SWEPCO was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenors appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

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 SWEPCo is unable to complete the Turk Plant construction, including the related transmission facilities, and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo’s Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of June 30, 2010, the Stall Unit cost $422 million, including $49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap.

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2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on equity of 11.5%. The filing included requests for 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. In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on equity of 10.33%, which consists of $5 million related to construction of the Stall Unit and $10 million in other increases. In addition, the settlement agreement will decrease annual depreciation expense by $17 million and allows SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from $3 million to $30 million in SWEPCo's $755 million fuel and purchase power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. Management is unable to predict the outcome of this reconciliation. If the PUCT disallows any portion of SWEPCo's fuel and purchase power costs, it could reduce future net income and cash flows and possibly impact financial condition.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring 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 also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision.
- The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.
- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. This decision could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income and cash flows and possibly impact financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of $103 million plus interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS' private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. TCC is not accruing interest on the $103 million because it is not probable that the PUCT will order TCC to violate the normalization provision of the Internal Revenue Code. If interest were accrued, management estimates interest expense would have been approximately $17 million higher for the period July 2008 through June 2010.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the resulting normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates $102 million as of June 30, 2010. 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 its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows and impact 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 costs in the true-up proceeding.

Certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows and impact financial condition. Management cannot predict the outcome of the excess earnings remand.

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

TCC filed a base rate case in 2006 seeking to increase base rates. The PUCT issued an order in 2007 which increased TCC's base rates by $20 million, eliminated a merger credit rider of $20 million and reduced depreciation rates by $7 million. The PUCT decision was appealed by TCC and various intervenors. On appeal, the Texas District Court affirmed the PUCT in most respects. Various intervenors appealed that decision. In June 2010, the Texas Court of Appeals affirmed the Texas District Court's decision.

ETT 2007 Formation Appeal

ETT is a joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC. TCC and TNC have sold transmission assets both in service and under construction to ETT. The PUCT approved ETT's initial rates, a request for a transfer of in-service assets and CWIP and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in ERCOT. ETT was allowed a 9.96% return on equity. Intervenors appealed the PUCT’s decision. In March 2010, the Texas Court of Appeals affirmed the PUCT's decision in all material respects. In April 2010, intervenors filed for rehearing at the Texas Court of Appeals which was denied in May 2010.

In a separate development, the Texas governor signed a new law that clarifies the PUCT's authority to grant CCNs to transmission only utilities such as ETT. ETT filed an application with the PUCT for a CCN under the new law. In March 2010, the PUCT approved the application for a CCN under the new law.

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a $62 million increase based on a 10.53% return on equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project, which resulted in a pretax write-off of $54 million in the second quarter of 2010. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral in the second quarter of 2010 of approximately $25 million of incremental storm expense incurred in 2009. In July 2010, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. Hearings are scheduled for December 2010. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO2. In October 2009, APCo started injecting CO2 into the underground storage facilities. The injection of CO2 required the recording of an asset retirement obligation and an offsetting regulatory asset. Through June 30, 2010, APCo has recorded a noncurrent regulatory asset of $58 million consisting of $38 million in project costs and $20 million in asset retirement costs.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a write-off of approximately $54 million in the second quarter of 2010. In response to the order, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. See "2009 Virginia Base Rate Case" section above.

In APCo's May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its estimated increased West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. If APCo cannot recover its remaining investment in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition.