AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 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 March 31, 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 its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

	Yes		No

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

Large accelerated filer	X	Accelerated filer	
Non-accelerated filer		Smaller reporting company	

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See the definitions of ‘large accelerated filer,’ ‘accelerated filer’ and ‘smaller reporting company’ in Rule 12b-2 of the Exchange Act.

Large accelerated filer		Accelerated filer	
Non-accelerated filer	X	Smaller reporting company	

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

	Yes		No	X

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

	Number of shares of common stock outstanding of the registrants at April 29, 2010
American Electric Power Company, Inc.	478,873,651 ($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
March 31, 2010

Glossary of Terms

Forward-Looking Information

Part I. FINANCIAL INFORMATION

Items 1, 2 and 3 - Financial Statements, Management's Financial Discussion and Analysis and Quantitative and Qualitative Disclosures About Risk Management Activities:

American Electric Power Company, Inc. and Subsidiary Companies:
- Management's Financial Discussion and Analysis of Results of Operations
- Quantitative and Qualitative Disclosures About Risk Management Activities
- Condensed Consolidated Financial Statements
- Index to Condensed Notes to Condensed Consolidated Financial Statements

Appalachian Power Company and Subsidiaries:
- Management's Financial Discussion and Analysis
- Quantitative and Qualitative Disclosures About Risk Management Activities
- Condensed Consolidated Financial Statements
- Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Columbus Southern Power Company and Subsidiaries:
- Management's Narrative Financial Discussion and Analysis
- Quantitative and Qualitative Disclosures About Risk Management Activities
- Condensed Consolidated Financial Statements
- Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Indiana Michigan Power Company and Subsidiaries:
- Management's Narrative Financial Discussion and Analysis
- Quantitative and Qualitative Disclosures About Risk Management Activities
- Condensed Consolidated Financial Statements
- Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Ohio Power Company Consolidated:
- Management's Financial Discussion and Analysis
- Quantitative and Qualitative Disclosures About Risk Management Activities
- Condensed Consolidated Financial Statements
- Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Public Service Company of Oklahoma:
- Management's Narrative Financial Discussion and Analysis
- Quantitative and Qualitative Disclosures About Risk Management Activities
- Condensed Financial Statements
- Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Southwestern Electric Power Company Consolidated:

Management's Financial Discussion and Analysis
Quantitative and Qualitative Disclosures About Risk Management Activities
Condensed Consolidated Financial Statements
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries

Combined Management's Discussion and Analysis of Registrant Subsidiaries

Controls and Procedures

Part II. OTHER INFORMATION

Item 1.	Legal Proceedings	
Item 1A.	Risk Factors	
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	
Item 5.	Other Information	
Item 6.	Exhibits:	
		Exhibit 10
		Exhibit 12
		Exhibit 31(a)
		Exhibit 31(b)
		Exhibit 32(a)
		Exhibit 32(b)

SIGNATURE

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.
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 distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
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.
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 distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms, 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 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.
- 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

In comparing first quarter 2010 results to the prior year, retail margins increased due to rate increases in various jurisdictions and higher residential demand for electricity as a result of favorable weather. Additionally, margins from off-system sales increased in 2010 primarily due to higher physical sales in our eastern region reflecting favorable generation availability. These margins were partially offset by lower commercial KWH sales due to continued weaknesses in the economy and lower industrial KWH sales due to reduced operations by several of our largest industrial customers.

Company-wide Staffing and Budget Review

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, we are currently conducting initiatives to achieve workforce reductions and significantly reduce other operation and maintenance spending. Achieving these goals will involve identifying process improvements, streamlining organizational designs and developing other efficiencies that can deliver additional sustainable savings.

Regulatory Activity

Our significant 2010 rate proceedings include:

Kentucky – In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. In April 2010, the Kentucky Industrial Utility Customers recommended an annual base revenue increase of no more than $41 million. New rates are expected to become effective in July 2010.

Michigan – In January 2010, I&M filed for a $63 million increase in annual Michigan base rates based on an 11.75% return on common equity. I&M can request interim rates, subject to refund, after six months. The MPSC must issue a final order within one year.

Ohio – Ohio law requires the PUCO to determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount would be returned to customers. The PUCO's decision determining a methodology is not expected to be finalized until a filing is made by CSPCo and OPCo in 2010 related to 2009 earnings and the PUCO issues an order thereon. As a result, CSPCo and OPCo are unable to determine whether they will be required to return any of their Ohio revenues to customers.

Oklahoma – In 2009, the OCC approved PSO's Capital Reliability Rider (CRR) filing which requires PSO to file a base rate case no later than July 2010.

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 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. The Virginia SCC staff and intervenors have recommended revenue increases ranging from $33 million to $94 million. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when Virginia newly enacted legislation suspended the collection of interim rates. The Virginia SCC is required to issue a final order no later than July 2010 with new rates effective August 2010.

West Virginia – APCo provided notice to the WVPSC that it intends to file a base rate case during 2010.

2010 Health Care Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the three months ended March 31, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

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 annually 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 Net Income by segment for the three months ended March 31, 2010 and 2009.

	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Utility Operations	$ 344	$ 346
AEP River Operations	3	11

Generation and Marketing	10	24
All Other (a)	(11)	(18)
Net Income	$ 346	$ 363

(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.

AEP CONSOLIDATED

First Quarter of 2010 Compared to First Quarter of 2009

Net Income in 2010 decreased $17 million compared to 2009 primarily due to the impact of OPEB taxes recorded in the first quarter of 2010 related to the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

Average basic shares outstanding increased to 478 million in 2010 from 407 million in 2009 primarily due to the issuance of 69 million shares of AEP common stock in April 2009. Actual shares outstanding were 479 million as of March 31, 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 March 31,	
	2010	2009
	(in millions)	
Revenues	$ 3,426	$ 3,267
Fuel and Purchased Power	1,247	1,196
Gross Margin	2,179	2,071
Depreciation and Amortization	398	373
Other Operating Expenses	1,040	994
Operating Income	741	704
Other Income, Net	43	30
Interest Expense	235	220
Income Tax Expense	205	168
Net Income	$ 344	$ 346

Summary of KWH Energy Sales for Utility Operations

For the Three Months Ended March 31, 2010 and 2009

Energy/Delivery Summary	2010	2009
	(in millions of KWH)	
Retail:		
Residential	17,774	16,371
Commercial	11,475	11,610
Industrial	13,381	13,522
Miscellaneous	713	719
Total Retail (a)	43,343	42,222
Wholesale	8,137	6,774
Total KWHs	51,480	48,996

(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 Months Ended March 31, 2010 and 2009

	2010	2009
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,900	1,820
Normal – Heating (b)	1,741	1,791
Actual – Cooling (c)	-	5
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	759	513
Normal – Heating (b)	574	579
Actual – Cooling (d)	20	99
Normal – Cooling (b)	58	56

(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.

First Quarter of 2010 Compared to First Quarter of 2009

Reconciliation of First Quarter 2009 to First Quarter of 2010
Net Income from Utility Operations
(in millions)

First Quarter of 2009		$346
Changes in Gross Margin:		
Retail Margins	169	
Off-system Sales	12	
Transmission Revenues	10	
Other Revenues	(83)	
Total Change in Gross Margin		108
Total Expenses and Other:		
Other Operation and Maintenance	(37)	
Depreciation and Amortization	(25)	
Taxes Other Than Income Taxes	(9)	
Interest and Investment Income	(3)	
Carrying Costs Income	5	
Allowance for Equity Funds Used During Construction	8	
Interest Expense	(15)	
Equity Earnings of Unconsolidated Subsidiaries	3	
Total Expenses and Other		(73)
Income Tax Expense		(37)
First Quarter of 2010		$344

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 $169 million primarily due to the following:
  - A $52 million increase related to an increase in interim rates in Virginia and the recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $31 million increase related to the PUCO's approval of our Ohio ESPs, a $12 million net rate increase for I&M, an $11 million increase in base rates in Oklahoma and $22 million of rate increases in our other jurisdictions.
  - A $38 million increase in weather-related usage primarily due to a 4% increase in heating degree days in our eastern region and a 48% increase in heating degree days in our western 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 shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.
  - These increases were offset by a $37 million decrease in non-weather usage due to reduced operations by several significant industrial customers, reduced usage by commercial customers due to difficult economic conditions

and the termination of an I&M unit power agreement.

- Margins from Off-system Sales increased $12 million primarily due to higher physical sales volumes in our eastern region reflecting favorable generation availability.
- Transmission Revenues increased $10 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- Other Revenues decreased $83 million primarily due to the Cook Plant accidental outage insurance proceeds of $54 million in the first quarter of 2009. I&M reduced customer bills by approximately $20 million in the first quarter of 2009 for the cost of replacement power during the outage period. This decrease in revenues 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 $19 million.

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

- Other Operation and Maintenance expenses increased $37 million primarily due to the following:
  - A $26 million increase in demand side management, energy efficiency and vegetation management programs.
  - A $23 million increase in transmission expenses, including base transmission work, RTO fees and transmission service expenses.
  - A $19 million increase in system improvements, reliability and other distribution expenses.
  - A $14 million increase in administrative and general expenses primarily for employee benefits.
  - A $5 million increase in plant outage and other plant operating and maintenance expenses.

  These increases were partially offset by:
  - A $35 million decrease in storm expenses.
  - A $15 million decrease in low income assistance programs and other customer accounts expense.
- Depreciation and Amortization increased $25 million primarily due to new environmental improvements placed in service and other increases in depreciable property balances.
- Taxes Other Than Income Taxes increased $9 million primarily due to increases in property and other taxes.
- Allowance for Equity Funds Used During Construction increased $8 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 $15 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 increased $37 million primarily due to the increase in pretax book income, the regulatory accounting treatment of state income taxes and the tax treatment associated with the future reimbursement of Medicare Part D prescription drug benefits.

AEP RIVER OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

Net Income from our AEP River Operations segment decreased from $11 million in 2009 to $3 million in 2010 primarily due to reduced grain loadings, higher fuel and other operating expenses and the recording of a gain on the sale of two older towboats in 2009.

GENERATION AND MARKETING

First Quarter of 2010 Compared to First Quarter of 2009

Net Income from our Generation and Marketing segment decreased from $24 million in 2009 to $10 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities partially offset by improved plant performance and hedging activities on our generation assets.

ALL OTHER

First Quarter of 2010 Compared to First Quarter of 2009

Net Loss from All Other decreased from a loss of $18 million in 2009 to a loss of $11 million in 2010 due to lower Parent related expenses.

AEP SYSTEM INCOME TAXES

First Quarter of 2010 Compared to First Quarter of 2009

Income Tax Expense increased $28 million in the first quarter of 2010 primarily due to 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. During the first quarter of 2010, we maintained our strong financial condition as reflected by our long-term debt issuances of $658 million primarily to fund our construction program and refinance debt maturities.

DEBT AND EQUITY CAPITALIZATION

	March 31, 2010			December 31, 2009		
			($ in millions)			
Long-term Debt, including amounts due within one year	$	17,534	54.8%	$	17,498	56.8%
Short-term Debt		1,063	3.3		126	0.4
Total Debt		18,597	58.1		17,624	57.2
Preferred Stock of Subsidiaries		61	0.2		61	0.2
AEP Common Equity		13,324	41.7		13,140	42.6
Total Debt and Equity Capitalization	$	31,982	100.0%	$	30,825	100.0%

Our ratio of debt to total capital increased from 57.2% to 58.1% in the first quarter of 2010 primarily due to an increase in short-term debt of $651 million as a result of a change in an accounting standard applicable to our sale of receivables agreement and an increase of $280 million in commercial paper outstanding.

Approximately $1.1 billion of our $18 billion of outstanding long-term debt will mature during the remaining three quarters of 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. In 2009, OPCo issued $500 million of 5.375% senior unsecured notes which we used in April 2010 to pay $400 million of OPCo's senior unsecured notes at maturity. We issued $658 million of long-term debt during the first quarter of 2010. We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations.

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 March 31, 2010, we had $3.6 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2010, our available liquidity was approximately $3.3 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
Revolving Credit Facility	$	1,500	March 2011
Revolving Credit Facility		1,454	April 2012
Revolving Credit Facility		627	April 2011
Total		3,581	
Cash and Cash Equivalents		818	
Total Liquidity Sources		4,399	
Less: AEP Commercial Paper Outstanding		399	
Letters of Credit Issued		652	
Net Available Liquidity	$	3,348	

We have credit facilities totaling $3.6 billion, of which two $1.5 billion credit facilities support our commercial paper program. The two $1.5 billion credit facilities allow for the issuance of up to $750 million as letters of credit under each credit facility. We also have a $627 million credit facility which can be utilized for letters of credit or draws.

It is our intent to renew the March 2011 facility. We are currently reviewing our options related to the April 2011 facility.

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 the first quarter of 2010 was $429 million. The weighted-average interest rate for our commercial paper during 2010 was 0.32%.

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 March 31, 2010, this contractually-defined percentage was 54.5%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 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 any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At March 31, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 400 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.42 per share in April 2010. Future dividends may vary depending upon our profit levels, operating cash flows and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the AEP Junior Subordinated Debentures 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, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

Our credit ratings as of March 31, 2010 were as follows:

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

In 2010, Moody's:

· Changed its rating outlook for AEP to stable from negative.

In 2010, Fitch:

· Changed its rating outlook for TCC to stable from negative.

Downgrades in our credit ratings by one of the rating agencies listed above could increase our borrowing costs.

CASH FLOW

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

	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 490	$ 411

Net Cash Flows from Operating Activities	2	317
Net Cash Flows Used for Investing Activities	(430)	(727)
Net Cash Flows from Financing Activities	756	709
Net Increase in Cash and Cash Equivalents	328	299
Cash and Cash Equivalents at End of Period	$ 818	$ 710

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

Operating Activities

	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Net Income	$ 346	$ 363
Depreciation and Amortization	408	382
Other	(752)	(428)
Net Cash Flows from Operating Activities	$ 2	$ 317

Net Cash Flows from Operating Activities were $2 million in 2010 consisting primarily of Net Income of $346 million, $408 million of noncash Depreciation and Amortization offset by $752 million in Other. 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 in Ohio and West Virginia and the favorable impact of decreases in fuel inventory and tax receivables. 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 $317 million in 2009 consisting primarily of Net Income of $363 million and $382 million of noncash Depreciation and Amortization. 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 the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity and an increase in under-recovered fuel primarily in Ohio and West Virginia.

Investing Activities

	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Construction Expenditures	$ (609)	$ (897)
Proceeds from Sales of Assets	139	172
Other	40	(2)
Net Cash Flows Used for Investing Activities	$ (430)	$ (727)

Net Cash Flows Used for Investing Activities were $430 million in 2010 primarily due to Construction Expenditures for new generation investment, environmental and distribution. Proceeds from Sales of Assets in 2010 includes $135 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $727 million in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investment plan. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners as planned.

Financing Activities

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(in millions)	
Issuance of Common Stock, Net	$ 26	$ 48
Issuance/Retirement of Debt, Net	952	854
Dividends Paid on Common Stock	(197)	(169)
Other	(25)	(24)
Net Cash Flows from Financing Activities	$ 756	$ 709

Net Cash Flows from Financing Activities were $756 million in 2010. Our net debt issuances were $296 million. The net issuances included issuances of $500 million of senior unsecured notes and $158 million of pollution control bonds, a $280 million increase in commercial paper outstanding and retirements of $490 million of senior unsecured notes, $86 million of securitization bonds and $54 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 $197 million.

Net Cash Flows from Financing Activities in 2009 were $709 million. Our net debt issuances were $854 million. The net issuances included issuances of $825 million of senior unsecured notes and $134 million of pollution control bonds and retirements of $84 million of securitization bonds. We paid common stock dividends of $169 million.

The following financing activities occurred or are expected to occur during 2010:

- In April 2010, OPCo retired $400 million of its outstanding Senior Unsecured Notes.
- We will refinance an additional $700 million of the remaining long-term debt that will mature in 2010.

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:

	March 31, 2010	December 31, 2009
	(in millions)	
AEP Credit Accounts Receivable Purchase Commitments	$ -	$ 631
Rockport Plant Unit 2 Future Minimum Lease Payments	1,920	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

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. In addition, an order is expected from the PUCO related to the SEET methodology. 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. The Texas District Court and the Texas Court of Appeals recommended the PUCT decision be modified on various issues which could have a favorable or unfavorable impact on TCC. After a ruling 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 a 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, 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. The Virginia Attorney General and the Virginia SCC staff have recommended in the pending Virginia base rate case that no recovery be allowed for the project. APCo plans to seek recovery of the West Virginia jurisdictional costs in its next West Virginia base rate filing which is expected to be filed in the second quarter of 2010. If APCo cannot recover all of its 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, with SWEPCo's share estimated to cost $1.3 billion, excluding AFUDC. Notices of appeal are outstanding at the Arkansas Supreme Court and the Circuit Court of Hempstead County, Arkansas. Complaints 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.

Company-wide Staffing and Budget Review

In April 2010, we began initiatives to decrease both labor and non-labor expenditures with a goal of achieving significant reductions in operation and maintenance expenses. One initiative is to offer a one-time voluntary severance program. Participating employees will receive two weeks of base pay for every year of service. It is anticipated that more than 2,000 employees will accept voluntary severances and terminate employment no later than May 2010. The second simultaneous initiative will involve all business units and departments to identify process improvements, streamlined organizational designs and other efficiencies that can deliver additional lasting savings. There is the potential that actions taken as a result of this effort could lead to some involuntary separations. Affected employees would receive the same severance package as those who volunteered.

We expect to record a charge to expense in the second quarter of 2010 related to these initiatives. At this time, we are unable to predict the impact of these initiatives on net income, cash flows and financial condition.

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. 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 and 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 environmental control requirements. The most significant source is the CAA's requirements to reduce emissions of SO2, NOx and PM from fossil fuel-fired power plants.

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.

Global Warming

While comprehensive economy-wide regulation of CO2 emissions might be achieved through new 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 approved in April 2010 for new motor vehicles are awaiting publication. 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 is expected to finalize 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 in 2010. 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. 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 CO2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). We are taking steps to comply with these requirements.

Certain groups have filed lawsuits alleging that emissions of CO2 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 CO2 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 the First Quarter of 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)
Three Months Ended March 31, 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	(24)	(6)	2	(28)
Fair Value of New Contracts at Inception When Entered During the Period (a)	6	7	-	13
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)	8	6	-	14

Changes in Fair Value Allocated to Regulated Jurisdictions (d)		25		-		-	25
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2010	$	147	$	152	$	(1)	298
Cash Flow Hedge Contracts							(4)
Collateral Deposits							134
Total MTM Derivative Contract Net Assets at March 31, 2010						$	428

(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 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 March 31, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 9.4%, 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 March 31, 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	$858	$76	$782	2	$ 227
Split Rating	5	-	5	1	5
Noninvestment Grade	1	-	1	2	1
No External Ratings:					
Internal Investment Grade	127	1	126	3	77

Internal Noninvestment Grade	105	12	93	3	78
Total as of March 31, 2010	$1,096	$89	$1,007	11	$ 388
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 March 31, 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

Three Months Ended March 31, 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 for both March 31, 2010 and December 31, 2009, the estimated EaR on our debt portfolio for the following twelve months was $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in millions, except per-share and share amounts)
(Unaudited)

REVENUES	2010	2009
Utility Operations	$3,406	$3,267
Other Revenues	163	191
TOTAL REVENUES	3,569	3,458
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	1,014	929
Purchased Electricity for Resale	238	295
Other Operation	673	610
Maintenance	271	295
Depreciation and Amortization	408	382
Taxes Other Than Income Taxes	207	197
TOTAL EXPENSES	2,811	2,708
OPERATING INCOME	758	750
Other Income (Expense):		
Interest and Investment Income	3	5
Carrying Costs Income	14	9
Allowance for Equity Funds Used During Construction	24	16
Interest Expense	(250)	(238)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	549	542
Income Tax Expense	207	179
Equity Earnings of Unconsolidated Subsidiaries	4	-
NET INCOME	346	363
Less: Net Income Attributable to Noncontrolling Interests	1	2
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	345	361
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$344	$360
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	478,429,535	406,826,606
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.72	$0.89
	478,844,632	407,381,954

WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING		
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.72	$0.89
CASH DIVIDENDS PAID PER SHARE	$0.41	$0.41

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 Three Months Ended March 31, 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	2	11	37				48
Common Stock Dividends				(167)		(2)	(169)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity						1	1
SUBTOTAL – EQUITY							10,589
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $1					3		3
Securities Available for Sale, Net of Tax of $1					(2)		(2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					5		5
NET INCOME				361		2	363
TOTAL COMPREHENSIVE INCOME							369
TOTAL EQUITY – MARCH 31, 2009	428	$ 2,782	$ 4,564	$ 4,040	$ (446)	$ 18	$ 10,958
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
Issuance of Common Stock	1	5	21				26
Common Stock Dividends				(196)		(1)	(197)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			2	(2)			-

SUBTOTAL – EQUITY							12,968
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $-					1		1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					5		5
NET INCOME				345		1	346
TOTAL COMPREHENSIVE INCOME							356
TOTAL EQUITY – MARCH 31, 2010	499	$ 3,244	$ 5,847	$ 4,597	$ (364)	$ -	$ 13,324

See Condensed Notes to Condensed Consolidated Financial Statements.

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

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$818	$490
Other Temporary Investments	238	363
Accounts Receivable:		
Customers	613	492
Accrued Unbilled Revenues	116	503
Pledged Accounts Receivable – AEP Credit	867	-
Miscellaneous	98	92
Allowance for Uncollectible Accounts	(38)	(37)
Total Accounts Receivable	1,656	1,050
Fuel	984	1,075
Materials and Supplies	582	586
Risk Management Assets	323	260
Accrued Tax Benefits	460	547
Regulatory Asset for Under-Recovered Fuel Costs	107	85
Margin Deposits	109	89
Prepayments and Other Current Assets	239	211
TOTAL CURRENT ASSETS	5,516	4,756
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	23,417	23,045
Transmission	8,313	8,315
Distribution	13,685	13,549
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,833	3,744
Construction Work in Progress	2,765	3,031
Total Property, Plant and Equipment	52,013	51,684
Accumulated Depreciation and Amortization	17,487	17,340
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	34,526	34,344
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,683	4,595
Securitized Transition Assets	1,865	1,896
Spent Nuclear Fuel and Decommissioning Trusts	1,433	1,392
Goodwill	76	76
Long-term Risk Management Assets	449	343
Deferred Charges and Other Noncurrent Assets	1,077	946
TOTAL OTHER NONCURRENT ASSETS	9,583	9,248
TOTAL ASSETS	$49,625	$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
March 31, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 954	$ 1,158
Short-term Debt:		
General	412	126
Securitized Debt for Receivables – AEP Credit	651	-
Total Short-term Debt	1,063	126
Long-term Debt Due Within One Year	1,253	1,741
Risk Management Liabilities	151	120
Customer Deposits	261	256
Accrued Taxes	621	632
Accrued Interest	254	287
Regulatory Liability for Over-Recovered Fuel Costs	38	76
Other Current Liabilities	920	931
TOTAL CURRENT LIABILITIES	5,515	5,327
NONCURRENT LIABILITIES		
Long-term Debt	16,281	15,757
Long-term Risk Management Liabilities	193	128
Deferred Income Taxes	6,587	6,420
Regulatory Liabilities and Deferred Investment Tax Credits	3,005	2,909
Asset Retirement Obligations	1,264	1,254
Employee Benefits and Pension Obligations	2,153	2,189
Deferred Credits and Other Noncurrent Liabilities	1,242	1,163
TOTAL NONCURRENT LIABILITIES	30,725	29,820
TOTAL LIABILITIES	36,240	35,147
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	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 499,133,697 / 498,333,265		
(20,278,858 shares were held in treasury at March 31, 2010 and December 31, 2009)	3,244	3,239
Paid-in Capital	5,847	5,824
Retained Earnings	4,597	4,451
Accumulated Other Comprehensive Income (Loss)	(364)	(374)

TOTAL AEP COMMON SHAREHOLDERS' EQUITY		13,324		13,140
Noncontrolling Interests		-		-
TOTAL EQUITY		13,324		13,140
TOTAL LIABILITIES AND EQUITY	$	49,625	$	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 Three Months Ended March 31, 2010 and 2009
(in millions)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$346	$363
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	408	382
Deferred Income Taxes	121	217
Carrying Costs Income	(14)	(9)
Allowance for Equity Funds Used During Construction	(24)	(16)
Mark-to-Market of Risk Management Contracts	(69)	(46)
Amortization of Nuclear Fuel	30	13
Property Taxes	(53)	(64)
Fuel Over/Under-Recovery, Net	(97)	(95)
Change in Other Noncurrent Assets	(28)	23
Change in Other Noncurrent Liabilities	37	18
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(617)	102
Fuel, Materials and Supplies	83	(118)
Margin Deposits	(20)	(39)
Accounts Payable	(83)	3
Customer Deposits	5	12
Accrued Taxes, Net	80	(57)
Accrued Interest	(34)	(44)
Other Current Assets	(14)	(7)
Other Current Liabilities	(55)	(321)
Net Cash Flows from Operating Activities	2	317
INVESTING ACTIVITIES		
Construction Expenditures	(609)	(897)
Change in Other Temporary Investments, Net	82	111
Purchases of Investment Securities	(445)	(179)
Sales of Investment Securities	473	158
Acquisitions of Nuclear Fuel	(38)	(76)
Proceeds from Sales of Assets	139	172
Other Investing Activities	(32)	(16)
Net Cash Flows Used for Investing Activities	(430)	(727)
FINANCING ACTIVITIES		
Issuance of Common Stock	26	48
Issuance of Long-term Debt	652	947
Borrowings from Revolving Credit Facilities	24	28
Change in Short-term Debt, Net	931	-
Retirement of Long-term Debt	(638)	(93)
Repayments to Revolving Credit Facilities	(17)	(28)
Principal Payments for Capital Lease Obligations	(24)	(23)
Dividends Paid on Common Stock	(197)	(169)

Dividends Paid on Cumulative Preferred Stock	(1)	(1)
Net Cash Flows from Financing Activities	756	709
Net Increase in Cash and Cash Equivalents	328	299
Cash and Cash Equivalents at Beginning of Period	490	411
Cash and Cash Equivalents at End of Period	$818	$710
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$271	$314
Net Cash Paid (Received) for Income Taxes	(2)	2
Noncash Acquisitions under Capital Leases	148	6
Construction Expenditures Included in Accounts Payable at March 31,	216	294
Acquisition of Nuclear Fuel Included in Accounts Payable at March 31,	3	17

See Condensed Notes to Condensed Consolidated Financial Statements.

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

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Acquisitions and Dispositions
6. Benefit Plans
7. Business Segments
8. Derivatives and Hedging
9. Fair Value Measurements
10. Income Taxes
11. Financing Activities
12. Company-wide Staffing and Budget Review

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 months ended March 31, 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 "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are currently the primary beneficiary of Sabine, DCC Fuel LLC (DCC Fuel), AEP Credit and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLC as defined by new accounting guidance for "Variable Interest Entities." In addition, we have not provided material financial or other support to Sabine, DCC Fuel, 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 March 31, 2010 and 2009 were $43 million and $35 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 of 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 March 31, 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. DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. DCC Fuel is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the lease will be made semi-annually on April 1 and October 1, beginning in April 2010. The lease was recorded as a capital lease on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 month lease term. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital lease is eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Condensed Consolidated Balance Sheets.

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 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 "ASU 2009-17 'Consolidation' " section of Note 2 for discussion of 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 wholly-owned subsidiary of SWEPCo. DHLC is a mining operator that 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 March 31, 2010 and March 31, 2009 were $13 million and $11 million, respectively. See the tables below for the classification of DHLC assets and liabilities on our Condensed Consolidated Balance Sheet at December 31, 2009 as well as our investment and maximum exposure as of March 31, 2010. As of March 31, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheet. Also, see "ASU 2009-17 'Consolidations' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

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

March 31, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit
ASSETS				
Current Assets	$ 51	$ 56	$ 145	$ 844
Net Property, Plant and Equipment	146	77	-	-
Other Noncurrent Assets	34	49	2	8
Total Assets	$ 231	$ 182	$ 147	$ 852
LIABILITIES AND EQUITY				
Current Liabilities	$ 35	$ 41	$ 42	$ 808
Noncurrent Liabilities	196	141	82	-
Equity	-	-	23	44
Total Liabilities and Equity	$ 231	$ 182	$ 147	$ 852

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

	SWEPCo Sabine	SWEPCo DHLC	I&M DCC Fuel	Protected Cell of EIS
ASSETS				
Current Assets	$ 51	$ 8	$ 47	$ 130
Net Property, Plant and Equipment	149	44	89	-