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

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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

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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
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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	-
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:

	March 31, 2010	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)	
Capital Contribution from Parent	$ 7	$ 7

Retained Earnings	1	1
SWEPCo's Guarantee of Debt	-	44
Total Investment in DHLC	$ 8	$ 52

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. Neither the "Ohio Series" or "Allegheny Series" are considered VIEs. 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 is expected to 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:

	March 31, 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 Parent	$ 14	$ 14	$ 13	$ 13
Retained Earnings	3	3	3	3
Total Investment in PATH-WV	$ 17	$ 17	$ 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 March 31,	
	2010	2009

	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 344		$ 360	
Weighted Average Number of Basic Shares Outstanding	478.4	$ 0.72	406.8	$ 0.89
Weighted Average Dilutive Effect of:				
Performance Share Units	0.3	-	0.5	-
Restricted Stock Units	0.1	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	478.8	$ 0.72	407.4	$ 0.89

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

Options to purchase 437,866 and 618,916 shares of common stock were outstanding at March 31, 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 quarter-end market price of the common shares, the effect would have been antidilutive.

Supplementary Information

	Three Months Ended March 31,	
	2010	2009
Related Party Transactions	(in millions)	
AEP Consolidated Revenues – Utility Operations:		
Ohio Valley Electric Corporation (43.47%) (a)	$ (9)	$ -
AEP Consolidated Revenues – Other Revenues:		
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	8	9
AEP Consolidated Expenses – Purchased Electricity for Resale:		
Ohio Valley Electric Corporation (43.47% Owned) (b)	77	70

(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 in 2010 includes $6 million related to the new agreement.

Adjustments to Reported Cash Flows

In the Financing Activities section of our Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2009, we corrected the presentation of borrowings on our lines of credit of $28 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 $28 million for the three months ended March 31, 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.

2. 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 The First Quarter of 2010

The following standards are effective during the first quarter 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.

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

March 31,

		December 31,
	2010	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	$57	$57
Storm Related Costs – CSPCo, OPCo, TCC	48	49
Line Extension Carrying Costs – CSPCo, OPCo	46	43
Acquisition of Monongahela Power – CSPCo	11	10
Regulatory Assets Currently Not Earning a Return		
Mountaineer Carbon Capture and Storage Project – APCo	111	111
Environmental Rate Adjustment Clause – APCo	27	25
Storm Related Costs – KPCo	24	24
Transmission Rate Adjustment Clause – APCo	21	26
Peak Demand Reduction/Energy Efficiency – CSPCo, OPCo	12	8
Special Rate Mechanism for Century Aluminum – APCo	12	12
Storm Related Costs – PSO	11	-
Deferred Wind Power Costs – APCo	11	5
Total Regulatory Assets Not Yet Being Recovered	$391	$370

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. 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 March 31, 2010 were $10 million and $345 million for CSPCo and OPCo, respectively, excluding $1 million and $13 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 another 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). The SEET 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 would be returned to customers. The PUCO staff recommended that the SEET be calculated on an individual company basis and not on a combined CSPCo/OPCo basis and that off-system sales margins be included in the earnings test. It is unclear at this time whether the FAC phase-in deferral credits will be included in the earnings test. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets until they are collected, assuming there are excessive earnings in that year. In April 2010, the PUCO heard arguments related to various SEET issues including the treatment of the FAC deferrals. The PUCO's decision on the SEET methodology is not expected to be finalized until a SEET filing is made by CSPCo and OPCo related to 2009 earnings and the PUCO issues an order thereon. In April 2010, CSPCo and OPCo filed a request with the PUCO to delay their SEET filing until July 2010. As a result, 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.

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 effective from January 2009 through September 2009. In January 2009, the PUCO approved the application. 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 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 balance. 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 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised several issues including (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 days 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.

As of March 31, 2010, CSPCo and OPCo have incurred $21 million and $12 million, respectively, in EDR costs. Of these costs, CSPCo and OPCo have collected $8 million and $6 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $13 million and $6 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. Management cannot predict the amounts CSPCo and OPCo will defer for future recovery through the EDR. 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 related to environmental investments in 2009. CSPCo's and OPCo's proposed initial rider would recover $29 million and $37 million, respectively, from July 2010 through December 2011 for carrying costs for 2009 through 2011. If approved, the implementation of the rider will likely not impact cash flows, but will impact the ESP phase-in plan deferrals associated with the FAC since this rider is within 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. 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 $24 million collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

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% 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. As of March 31, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $777 million of expenditures (including AFUDC and capitalized interest, and related transmission costs of $35 million). As of March 31, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $459 million (including related transmission costs of $7 million). SWEPCo's share of the contractual construction commitments is $337 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of March 31, 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). Following an appeal by certain intervenors, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the Turk Plant and the proposed transmission facilities' construction and location should have been considered by the APSC in a single docket instead of separate dockets. The Arkansas Supreme Court granted petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals' decision. The Court heard oral arguments in April 2010. A decision from the Arkansas Supreme Court is pending.

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 in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed the Texas District Court decision.

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 (ADEQ) and commenced construction at the site. In January 2010, 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 of the APCEC's decision 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.

Management believes that SWEPCo's planning, certification and construction of the Turk Plant has been in material compliance with all applicable laws and regulations. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if 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 reduce future net income and cash flows and impact financial condition.

Stall Unit

SWEPCo is constructing 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 Stall Unit is currently estimated to cost $431 million, including $51 million of AFUDC, and is expected to be in service in mid-2010. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs.

As of March 31, 2010, SWEPCo has capitalized construction costs of $402 million, including AFUDC, and has contractual construction commitments of an additional $17 million. If the final cost of the Stall Unit were to exceed the $445 million cost cap, the APSC or LPSC could disallow their jurisdictional allocation of construction costs in excess of the caps and thereby reduce future net income and cash flows and impact financial condition.

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.

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 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 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 $15 million higher for the period July 2008 through March 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 March 31, 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.

In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset of $55 million representing a receivable from the REPs for the refunds made to them by TCC. However, 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 the District Court's affirmation of the PUCT decision to the Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the intervenor appeals are successful, it could reduce future net income and cash flows and impact financial condition.

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 to the Travis County District Court. The court ruled that the PUCT exceeded its authority by approving ETT's application as a stand alone transmission utility without a service area under the wrong section of the statute. ETT and the PUCT filed appeals to the Texas Court of Appeals. In March 2010, the Texas Court of Appeals reversed the Travis County District Court and affirmed the PUCT's decision in all material respects.

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 for the purpose of confirming its authority to operate as a transmission only utility regardless of the outcome of the pending litigation. In March 2010, the PUCT approved the application for a CCN under the new law. In April 2010, intervenors filed a joint motion for rehearing at the Texas Court of Appeals.

As of March 31, 2010, ETT's investment in property, plant and equipment was $441 million, of which $39 million was under construction. Depending upon the result of ETT's CCN rehearing under the new law, TCC and TNC may be required to reacquire assets and projects under construction previously transferred to ETT by TCC and TNC. TCC and TNC would not be required to acquire the competitive renewable-energy zones projects. If TCC and TNC are required to reacquire these assets and projects, it could impact cash flows and financial condition.

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. 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. The enacted legislation also stated that depending on the revenue awarded, a refund of interim rates may not be necessary. If a refund is required, it would reduce future net income and cash flows and impact financial condition.

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 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 March 31, 2010, APCo has recorded a noncurrent regulatory asset of $111 million consisting of $72 million in project costs and $39 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. 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 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.

APCo's Filings for an IGCC Plant

APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC power plant in Mason County, West Virginia. APCo also requested the Virginia SCC and the WVPSC to approve a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. The WVPSC granted APCo the CPCN and approved the requested cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order.

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism based upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on an unfavorable order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

Through March 31, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and in West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

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

In September 2009, the WVPSC issued an order approving APCo's and WPCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $355 million and a first-year increase of $124 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan. In March 2010, APCo and WPCo filed its second-year request with the WVPSC to increase rates in July 2010 by $96 million. As of March 31, 2010, APCo's ENEC under-recovery balance was $318 million which is included in noncurrent regulatory assets.

The September 2009 order also lowered annual coal cost projections by $27 million and deferred recovery of unrecovered ENEC deferrals related to price increases on certain renegotiated coal contracts. The WVPSC indicated that it would review the prudency of these additional costs in the next ENEC proceeding. As of March 31, 2010, APCo has deferred $23 million of unrecovered coal costs on the renegotiated coal contracts which is included in APCo’s $318 million ENEC regulatory asset and has recorded an additional $5 million in fuel inventory related to the renegotiated coal contracts, which is recorded in Fuel on the balance sheets. Although management believes the portion of its deferred ENEC under-recovery balance attributable to renegotiated coal contracts is probable of recovery, if the WVPSC were to disallow a portion of APCo’s and WPCo’s deferred ENEC costs including any costs incurred in the future related to the renegotiated coal contracts, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of $42 million of PSO fuel costs. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) has contended that PSO should not have collected the $42 million without specific OCC approval. As such, the OIEC contends that the OCC should require PSO to refund the $42 million it collected through its fuel clause. The OCC has heard the OIEC appeal and a decision is pending. In March 2010, PSO filed motions to advance this proceeding since the FERC has ruled on the allocation of off-system sales margins proceeding and PSO has refunded the additional margins to its retail customers. If the OCC were to order PSO to refund all or a part of the $42 million, it would reduce future net income and cash flows and impact financial condition.

2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO’s fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudency review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder’s portion of off-system sales margins sharing decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. If the OCC were to issue an unfavorable decision, it would reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an $81 million increase in PSO’s non-fuel base revenues based on a 10.5% return on equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. If the intervenors’ appeals are successful, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

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

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately $53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4, Cook Unit 1 was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduce power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. A procedural schedule has been established for the subdocket with hearings expected to be held in November 2010.

Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition.

2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

Michigan Base Rate Filing

In January 2010, I&M filed for a $63 million increase in annual 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.

Kentucky Rate Matters

Kentucky Base Rate Filing

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. The base rate case also requested recovery of $24 million of deferred storm restoration expenses as of March 31, 2010 over a three-year period. In April 2010, the Kentucky Industrial Utility Customers filed testimony with the KPSC which recommends an annual base revenue increase of no more than $41 million based on a 10.1% return on common equity. New rates are expected to become effective in July 2010. If the KPSC denies recovery of the storm restoration regulatory asset, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues.

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

AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a refund of a portion or all of the unsettled SECA revenues. In December 2009, several parties filed a motion with the U.S. Court of Appeals to force the FERC to resolve the SECA issue.

The AEP East companies provided reserves for net refunds for SECA settlements applicable to the $220 million of SECA revenues collected. As of March 31, 2010, there were no in-process settlements.

Based on the AEP East companies' settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the reserve is adequate to settle the remaining $108 million of contested SECA revenues. Management cannot predict the ultimate outcome of future settlement discussions or future proceedings at the FERC or court of appeals. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it would reduce future net income and cash flows and impact financial condition.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. Settlement discussions are in progress. Once approved by the FERC, management is unable to predict whether the parties to the TA will experience regulatory lag and its effect on future net income and cash flows due to timing of the implementation of the modified TA by various state regulators.

PJM/MISO Market Flow Calculation Errors

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO disputes PJM's methodology.

Settlement discussions between MISO and PJM have been unsuccessful, and as a result, in March 2010, MISO filed two related complaints against PJM at the FERC related to the above claim. MISO seeks to recover a total of approximately $145 million from PJM. Given that PJM passes its costs on to its members, if PJM is held liable for these damages, PJM members, including the AEP East companies, may be held responsible for a share of the refunds or payments PJM is directed to make to MISO. AEP has intervened and filed a protest to one complaint. Management believes that MISO's claims filed at the FERC are without merit and that PJM's right to recover from AEP and other members any damages awarded to MISO is limited. If the FERC orders a settlement above the AEP East companies' reserve related to their estimated portion of PJM additional costs, it could reduce future net income and cash flows and impact financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2009 Annual Report should be read in conjunction with this report.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. As of March 31, 2010, the maximum future payments for LOCs issued under the two $1.5 billion 5-year credit facilities are $175 million with maturities ranging from May 2010 to June 2011.

We have a $627 million 3-year credit agreement. As of March 31, 2010, $477 million of LOCs with maturities ranging from May 2010 to November 2010 were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036. A new study is in process to include new, expanded areas of the mine. As of March 31, 2010, SWEPCo has collected approximately $45 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $21 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $22 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sales agreements is discussed in the 2009 Annual Report, “Dispositions” section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.1 billion. Approximately $1 billion of the maximum exposure relates to the Bank of America (BOA) litigation (see “Enron Bankruptcy” section of this note), of which the probable payment/performance risk is $443 million and is recorded in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets as of March 31, 2010. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, we will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008 and 2009, we signed new master lease agreements that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At March 31, 2010, the maximum potential loss for these lease agreements was approximately $3 million assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $18 million for I&M and $21 million for SWEPCo for the remaining railcars as of March 31, 2010.

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

We have other railcar lease arrangements that do not utilize this type of financing structure.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. Following a second liability trial in 2009, the jury again found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. Beckjord is operated by Duke Energy Ohio, Inc.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in a pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in a previous state permit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. We are unable to predict the timing of any future action by the Federal EPA or the effect of such action on our net income, cash flows or financial condition.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. The defendants' petition for rehearing was denied.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing and scheduled oral argument for May 24, 2010. We were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint.

We believe the actions are without merit and intend to continue to defend against the claims.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. We believe the action is without merit and intend to defend against the claims.

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

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

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M to take voluntary action necessary to prevent and/or mitigate public harm. In May 2008, I&M started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $11 million of expense prior to January 1, 2010, $3 million of which I&M recorded in March 2009. As the remediation work is completed, I&M's cost may continue to increase. I&M cannot predict the amount of additional cost, if any.

Amos Plant – Request to Show Cause

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. We indicated our willingness to engage in good faith negotiations and meet with representatives of the Federal EPA. We have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several units utilizing the jet bubbling reactor (JBR) technology. The following plants have been scheduled for the installation of the JBR technology or are currently utilizing JBR retrofits:

Plant Name	Plant Owners	JBRs Installed/ Scheduled for Installation
Cardinal	OPCo/ Buckeye Power, Inc.	3
Conesville	CSPCo/Dayton Power and Light Company/ Duke Energy Ohio, Inc.	1
Clifty Creek	Indiana-Kentucky Electric Corporation	2
Kyger Creek	Ohio Valley Electric Corporation	2
Muskingum River (a)	OPCo	1
Big Sandy (a)	KPCo	1

(a) Contracts for the Muskingum River and Big Sandy projects have been temporarily suspended during the early development stages of the projects.

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

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in

2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

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 significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. 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 these 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.

I&M maintains property insurance through NEIL with a $1 million deductible. As of March 31, 2010, we recorded $143 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheet representing recoverable amounts under the property insurance policy. Through March 31, 2010, I&M received partial payments of $118 million from NEIL for the cost incurred to repair the property damage. In April 2010, I&M received a $45 million payment from NEIL.

I&M also maintained a separate accidental outage insurance policy with NEIL. In 2009, I&M recorded $185 million in revenue under this policy and reduced the cost of replacement power in customers' bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Fort Wayne Lease

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

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute is being litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

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

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. The lawsuit asserts that BOA made representations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false. In 2005, the Judge entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. Trial in federal court in Texas was continued pending a decision in the New York case.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the court entered a final judgment of $346 million. We appealed and posted a bond covering the amount of the judgment entered against us. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed this award and posted bond covering that amount. In September 2009, the United States Court of Appeals for the Second Circuit heard oral argument on our appeal.

The liability for the BOA litigation was $443 million and $441 million including interest at March 31, 2010 and December 31, 2009, respectively. These liabilities are included in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we have for the remaining cases is adequate.

5. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

2010

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). The current estimate of the purchase is $99 million, plus the assumption of certain liabilities, subject to adjustments at closing. Consummation of the transaction is subject to regulatory approval by the LPSC, the APSC, the Rural Utilities Service and the National Rural Utilities Cooperative Finance Corporation. In January 2010, the VEMCO members approved the transaction. In April 2010, a joint application between SWEPCo and VEMCO was filed with the LPSC. SWEPCo will seek recovery from Louisiana customers for all costs related to this acquisition. VEMCO services approximately 30,000 customers in Louisiana. SWEPCo expects to complete the transaction in the third quarter of 2010 upon receipt of regulatory and other approvals.

2009

None

DISPOSITIONS

2010

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In 2010, TCC and TNC sold $64 million and $71 million, respectively, of transmission facilities to ETT. There were no gains or losses recorded on these transactions.

2009

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In January 2009, TCC sold $60 million of transmission facilities to ETT. There were no gains or losses recorded on these transactions.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the three months ended March 31, 2010 and 2009:

	Pension Plans Three Months Ended March 31,		Other Postretirement Benefit Plans Three Months Ended March 31,	
	2010	2009	2010	2009
	(in millions)			
Service Cost	$28	$26	$12	$10
Interest Cost	63	63	28	27

Expected Return on Plan Assets	(78)	(80)	(26)	(20)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	22	15	7	11
Net Periodic Benefit Cost	$35	$24	$28	$35

7. BUSINESS SEGMENTS

As outlined in our 2009 Annual Report, our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

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

AEP River Operations
- Commercial barging operations that annually transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

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

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

- Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which gradually settle and completely expire in 2011.

The tables below present our reportable segment information for the three months ended March 31, 2010 and 2009 and balance sheet information as of March 31, 2010 and December 31, 2009. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
Three Months Ended March 31, 2010	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 3,406	$ 121	$ 47	$ (5)	$ -	$ 3,569
Other Operating Segments	20	5	-	8	(33)	-
Total Revenues	$ 3,426	$ 126	$ 47	$ 3	$ (33)	$ 3,569

Net Income (Loss)	$ 344	$ 3	$ 10	$ (11)	$ -	$ 346

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Three Months Ended March 31, 2009						
Revenues from:						
External Customers	$ 3,267 (d)	$ 123	$ 87	$ (19)	$ -	$ 3,458
Other Operating Segments	- (d)	6	5	22	(33)	-
Total Revenues	$ 3,267	$ 129	$ 92	$ 3	$ (33)	$ 3,458
Net Income (Loss)	$ 346	$ 11	$ 24	$ (18)	$ -	$ 363

		Nonutility Operations				
March 31, 2010	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)		
Total Property, Plant and Equipment	$ 51,168	$ 502	$ 584	$ 10	$ (251)	$ 52,013
Accumulated Depreciation and Amortization	17,247	92	176	9	(37)	17,487
Total Property, Plant and Equipment – Net	$ 33,921	$ 410	$ 408	$ 1	$ (214)	$ 34,526
Total Assets	$ 48,066	$ 551	$ 832	$ 14,996	$ (14,820)(c)	$ 49,625

		Nonutility Operations				
December 31, 2009	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)		
Total Property, Plant and Equipment	$ 50,905	$ 436	$ 571	$ 10	$ (238)	$ 51,684
Accumulated Depreciation and Amortization	17,110	88	168	8	(34)	17,340
Total Property, Plant and Equipment – Net	$ 33,795	$ 348	$ 403	$ 2	$ (204)	$ 34,344
Total Assets	$ 46,930	$ 495	$ 779	$ 15,094	$ (14,950)(c)	$ 48,348

(a) All Other includes:

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

· Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which gradually settle and completely expire in 2011.

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

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

(d) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This is offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of $(5) million for the three months ended March 31, 2009. The Generation and Marketing segment also reports these purchases or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

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

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

The following table represents the gross notional volume of our outstanding derivative contracts as of March 31, 2010 and December 31, 2009:

Notional Volume of Derivative Instruments

Volume

	March 31, 2010	December 31, 2009	Unit of Measure
	(in millions)		
Commodity:			
Power	523	589	MWHs
Coal	72	60	Tons
Natural Gas	137	127	MMBtus
Heating Oil and Gasoline	7	6	Gallons
Interest Rate	$ 194	$ 216	USD
Interest Rate and Foreign Currency	$ 329	$ 83	USD

Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

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

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

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2010 and December 31, 2009 balance sheets, we netted $36 million and $12 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $170 million and $98 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our Condensed Consolidated Balance Sheet as of March 31, 2010 and December 31, 2009:

Fair Value of Derivative Instruments
March 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in millions)		
Current Risk Management Assets	$ 1,614	$ 25	$ -	$ (1,316)	$ 323
Long-term Risk Management Assets	933	6	-	(490)	449
Total Assets	2,547	31	-	(1,806)	772
Current Risk Management Liabilities	1,522	25	4	(1,400)	151
Long-term Risk Management Liabilities	792	4	2	(605)	193
Total Liabilities	2,314	29	6	(2,005)	344

Total MTM Derivative Contract Net Assets (Liabilities)	$ 233	$ 2	$ (6)	$ 199	$ 428

Fair Value of Derivative Instruments
December 31, 2009

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in millions)		
Current Risk Management Assets	$ 1,078	$ 13	$ -	$ (831)	$ 260
Long-term Risk Management Assets	614	-	-	(271)	343
Total Assets	1,692	13	-	(1,102)	603
Current Risk Management Liabilities	997	17	3	(897)	120
Long-term Risk Management Liabilities	442	-	2	(316)	128
Total Liabilities	1,439	17	5	(1,213)	248
Total MTM Derivative Contract Net Assets (Liabilities)	$ 253	$ (4)	$ (5)	$ 111	$ 355

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Consolidated Balance Sheet on a net basis in accordance with the accounting guidance for “Derivatives and Hedging.”
(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for “Derivatives and Hedging” and dedesignated risk management contracts.

The table below presents our activity of derivative risk management contracts for the three months ended March 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2010 and 2009

Location of Gain (Loss)	2010	2009
	(in millions)	

Utility Operations Revenue	$ 38	$ 65
Other Revenue	1	13
Regulatory Assets (a)	-	(1)
Regulatory Liabilities (a)	42	34
Total Gain on Risk Management Contracts	$ 81	$ 111

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current within the balance sheet.

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

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

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

Accounting for Fair Value Hedging Strategies

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

We record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Condensed Consolidated Statements of Income. During the three months ended March 31, 2010, we designated interest rate derivatives as fair value hedges. During the three months ended March 31, 2010, no hedge ineffectiveness was recognized. During the three months ended March 31, 2009, we did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal, heating oil and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Condensed Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Condensed Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2010 and 2009, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Condensed Consolidated Statements of Income. During the three months ended March 31, 2010 and 2009, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2010 and 2009, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Depreciation and Amortization expense on our Condensed Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2010 and 2009, we designated foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2010 and 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of January 1, 2010	$(2)	$(13)	$(15)
Changes in Fair Value Recognized in AOCI	3	(1)	2
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	-	-	-
Other Revenue	(1)	-	(1)
Purchased Electricity for Resale	1	-	1
Interest Expense	-	1	1
Regulatory Assets (a)	1	-	1
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of March 31, 2010	$2	$(13)	$(11)

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

For the Three Months Ended March 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of January 1, 2009	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(3)	-	(3)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(2)	-	(2)
Other Revenue	(2)	-	(2)
Purchased Electricity for Resale	8	-	8
Interest Expense	-	1	1
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	(1)	-	(1)
Balance in AOCI as of March 31, 2009	$ 9	$ (28)	$ (19)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current within the balance sheet.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheet at March 31, 2010 and December 31, 2009 were:

Impact of Cash Flow Hedges
Condensed Consolidated Balance Sheet
March 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 16	$ -	$ 16
Hedging Liabilities (a)	(14)	(6)	(20)
AOCI Loss Net of Tax	2	(13)	(11)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	-	(4)	(4)

Impact of Cash Flow Hedges
Condensed Consolidated Balance Sheet
December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 8	$ -	$ 8
Hedging Liabilities (a)	(12)	(5)	(17)
AOCI Loss Net of Tax	(2)	(13)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(2)	(4)	(6)

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

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2010, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 45 months.

Credit Risk

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

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We believe that a downgrade below investment grade is unlikely. The following table represents our aggregate fair value of such derivative contracts, the amount of collateral we would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of March 31, 2010 and December 31, 2009:

	Aggregate Fair Value of Derivative Contracts	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in millions)	
March 31, 2010	$ 9	$ 34	$ 32
December 31, 2009	10	34	29

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under borrowed debt in excess of

$50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. We believe that a non-performance event under these provisions is unlikely. The following table represents the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, the amount this exposure has been reduced by cash collateral we have posted and if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of March 31, 2010 and December 31, 2009:

	Liabilities of Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
March 31, 2010	$ 794	$ 48	$ 287
December 31, 2009	567	15	199

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for “Fair Value Measurements and Disclosures” establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee’s external pricing service in our estimate of the fair value of the underlying investments held in the nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	United States Government	Corporate Debt	State and Local Government
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates			X
Prepayment Schedule and History			X
Yield Adjustments	X		

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt as of March 31, 2010 and December 31, 2009 are summarized in the following table:

	March 31, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,534	$ 18,647	$ 17,498	$ 18,479

Fair Value Measurements of Other Temporary Investments

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

The following is a summary of Other Temporary Investments:

	March 31, 2010			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 141	$ -	$ -	$ 141
Fixed Income Securities – Mutual Funds	58	-	-	58
Equity Securities:				
Domestic	1	15	-	16
Mutual Funds	18	5	-	23
Total Other Temporary Investments	$ 218	$ 20	$ -	$ 238

	December 31, 2009			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Cash and Cash Equivalents (a)	$ 223	$ -	$ -	$ 223
Debt Securities	102	-	-	102
Equity Securities	19	19	-	38
Total Other Temporary Investments	$ 344	$ 19	$ -	$ 363

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

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the three months ended March 31, 2010 and 2009:

Three Months Ended March 31,	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
	(in millions)			
2010	$ 241	$ 197	$ -	$ -
2009	-	-	-	-

At March 31, 2010, we had no Other Temporary Investments with an unrealized loss position. At March 31, 2010, debt securities primarily include debt based mutual funds with short and intermediate maturities and variable rate demand notes.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.
- Target asset allocation is 50% fixed income and 50% equity securities.

We maintain trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

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

The following is a summary of nuclear trust fund investments at March 31, 2010 and December 31, 2009:

	March 31, 2010			December 31, 2009		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
			(in millions)			
Cash and Cash Equivalents	$ 16	$ -	$ -	$ 14	$ -	$ -
Fixed Income Securities:						
United States Government	451	15	(2)	401	13	(4)
Corporate Debt	59	5	(2)	57	5	(2)
State and Local Government	326	3	-	369	8	1
Subtotal Fixed Income Securities	836	23	(4)	827	26	(5)
Equity Securities – Domestic	581	261	(118)	551	234	(119)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,433	$ 284	$ (122)	$ 1,392	$ 260	$ (124)

The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2010 and 2009:

Three Months Ended March 31,	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
		(in millions)		
2010	$ 232	$ 248	$ 5	$ -
2009	158	178	3	-

The adjusted cost of debt securities was $813 million and $801 million as of March 31, 2010 and December 31, 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at March 31, 2010 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 15
1 year – 5 years	309
5 years – 10 years	256
After 10 years	256
Total	$ 836

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2010 and December 31, 2009. As required by the accounting guidance for “Fair Value Measurements and Disclosures,” financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP’s valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 733	$ -	$ -	$ 85	$ 818
Other Temporary Investments					
Restricted Cash (a)	106	-	-	35	141
Fixed Income Securities – Mutual Funds	58	-	-	-	58
Equity Securities (c):					

Domestic	16	-	-	-	16
Mutual Funds	23	-	-	-	23
Total Other Temporary Investments	203	-	-	35	238
Risk Management Assets					
Risk Management Commodity Contracts (d) (g)	22	2,360	148	(1,839)	691
Cash Flow Hedges:					
Commodity Hedges (d)	11	20	-	(15)	16
Dedesignated Risk Management Contracts (e)	-	-	-	65	65
Total Risk Management Assets	33	2,380	148	(1,789)	772
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	-	6	-	10	16
Fixed Income Securities:					
United States Government	-	451	-	-	451
Corporate Debt	-	59	-	-	59
State and Local Government	-	326	-	-	326
Subtotal Fixed Income Securities	-	836	-	-	836
Equity Securities – Domestic (c)	581	-	-	-	581
Total Spent Nuclear Fuel and Decommissioning Trusts	581	842	-	10	1,433
Total Assets	$ 1,550	$ 3,222	$ 148	$ (1,659)	$ 3,261
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (d) (g)	$ 27	$ 2,238	$ 32	$ (1,973)	$ 324
Cash Flow Hedges:					
Commodity Hedges (d)	2	27	-	(15)	14
Interest Rate/Foreign Currency Hedges	-	6	-	-	6
Total Risk Management Liabilities	$ 29	$ 2,271	$ 32	$ (1,988)	$ 344

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Cash and Cash Equivalents (a)	$ 427	$ -	$ -	$ 63	$ 490
Other Temporary Investments					
Cash and Cash Equivalents (a)	198	-	-	25	223
Debt Securities (b)	57	45	-	-	102
Equity Securities (c)	38	-	-	-	38
Total Other Temporary Investments	293	45	-	25	363

Risk Management Assets										
Risk Management Contracts (d) (h)		8		1,609		72		(1,119)		570
Cash Flow Hedges (d)		1		11		-		(4)		8
Dedesignated Risk Management Contracts (e)		-		-		-		25		25
Total Risk Management Assets		9		1,620		72		(1,098)		603
Spent Nuclear Fuel and Decommissioning Trusts										
Cash and Cash Equivalents (f)		-		3		-		11		14
Fixed Income Securities:										
United States Government		-		401		-		-		401
Corporate Debt		-		57		-		-		57
State and Local Government		-		369		-		-		369
Subtotal Fixed Income Securities		-		827		-		-		827
Equity Securities (c)		551		-		-		-		551
Total Spent Nuclear Fuel and Decommissioning Trusts		551		830		-		11		1,392
Total Assets	$	1,280	$	2,495	$	72	$	(999)	$	2,848
Liabilities:										
Risk Management Liabilities										
Risk Management Contracts (d) (h)	$	11	$	1,415	$	10	$	(1,205)	$	231
Cash Flow Hedges (d)		-		21		-		(4)		17
Total Risk Management Liabilities	$	11	$	1,436	$	10	$	(1,209)	$	248

(a) Amounts in “Other” column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.
(b) Amounts represent debt-based mutual funds.
(c) Amounts represent publicly traded equity securities and equity-based mutual funds.
(d) Amounts in “Other” column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for “Derivatives and Hedging.”
(e) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for “Derivatives and Hedging.” At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(f) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(g) The March 31, 2010 maturity of the net fair value of risk management commodity contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($1) million in 2010, ($2) million in periods 2011-2013 and ($2) million in periods 2014-2015; Level 2 matures $44 million in 2010, $57 million in periods 2011-2013, $0 million in periods 2014-2015 and $21 million in periods 2016-2028; Level 3 matures $28 million in 2010, $35 million in periods 2011-2013, $29 million in periods 2014-2015 and $24 million in periods 2016-2028. Risk management commodity contracts are substantially comprised of power contracts.

(h) The December 31, 2009 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($1) million in 2010, ($1) million in periods 2011-2013 and ($1) million in periods 2014-2015; Level 2 matures $65 million in 2010, $84 million in periods 2011-2013, $22 million in periods 2014-2015 and $23 million in periods 2016-2028; Level 3 matures $17 million in 2010, $16 million in periods 2011-2013, $8 million in periods 2014-2015 and $21 million in periods 2016-2028.

There have been no transfers between Level 1 and Level 2 during the three months ended March 31, 2010.

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

Three Months Ended March 31, 2010	Net Risk Management Assets (Liabilities) (in millions)
Balance as of January 1, 2010	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	27
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	24
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(31)
Transfers into Level 3 (d) (h)	15
Transfers out of Level 3 (e) (h)	1
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	18
Balance as of March 31, 2010	$ 116

Three Months Ended March 31, 2009	Net Risk Management Assets (Liabilities) (in millions)
Balance as of January 1, 2009	$ 49
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(12)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	59
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements	-
Transfers in and/or out of Level 3 (f)	(25)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of March 31, 2009	$ 86

(a) Included in revenues on our Condensed Consolidated Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable

during the period.

(g) Relates to the net gains (losses) of those contracts that are not reflected on our Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

(h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

10. INCOME TAXES

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

We are no longer subject to U.S. federal examination for years before 2001. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

Federal 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.

11. FINANCING ACTIVITIES

Long-term Debt

Type of Debt	March 31, 2010	December 31, 2009
	(in millions)	
Senior Unsecured Notes	$ 12,423	$ 12,416
Pollution Control Bonds	2,263	2,159
Notes Payable	316	326

Securitization Bonds	1,909	1,995
Junior Subordinated Debentures	315	315
Spent Nuclear Fuel Obligation (a)	265	265
Other Long-term Debt	88	88
Unamortized Discount (net)	(45)	(66)
Total Long-term Debt Outstanding	17,534	17,498
Less Portion Due Within One Year	1,253	1,741
Long-term Portion	$ 16,281	$ 15,757

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation of $306 million at March 31, 2010 and December 31, 2009 are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2010 are shown in the tables below.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$ 18	4.625	2021
CSPCo	Floating Rate Notes	150	Variable	2012
OPCo	Pollution Control Bonds	86	3.125	2043
SWEPCo	Senior Unsecured Notes	350	6.20	2040
SWEPCo	Pollution Control Bonds	54	3.25	2015
Total Issuances		$ 658 (a)		

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

(a) Amount indicated on statement of cash flows of $652 million is net of issuance costs and premium or discount.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
AEP	Senior Unsecured Notes	$ 490	5.375	2010
SWEPCo	Pollution Control Bonds	54	Variable	2019
Non-Registrant:				
AEP Subsidiaries	Notes Payable	4	Variable	2017
AEGCo	Senior Unsecured Notes	4	6.33	2037
TCC	Securitization Bonds	32	5.56	2010
TCC	Securitization Bonds	54	4.98	2010
Total Retirements and Principal Payments		$ 638		

As of March 31, 2010, trustees held, on our behalf, $303 million of our reacquired auction-rate tax-exempt long-term debt.

In April 2010, OPCo retired $400 million of variable rate Senior Unsecured Notes due in 2010 and I&M issued $85 million of 4.00% Notes Payable due in 2014.

Dividend Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. 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.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068. We have the option to defer interest payments on the 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 do not anticipate any deferral of those interest payments in the foreseeable future.

Pursuant to the leverage restrictions in our credit agreements, as of March 31, 2010, none of our retained earnings were restricted for the purpose of the payment of dividends.

Short-term Debt

Our outstanding short-term debt was as follows:

	March 31, 2010		December 31, 2009	
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
Securitized Debt for Receivables (b)	$ 651	0.24%	$ -	-
Commercial Paper	399	0.35%	119	0.26%
Line of Credit – Sabine Mining Company (c)	13	2.12%	7	2.06%
Total	$ 1,063		$ 126	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance. See "ASU 2009-16 'Transfers and Servicing' " section of Note 2.
(c) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

We have credit facilities totaling $3 billion to support our commercial paper program. The facilities are structured as two $1.5 billion credit facilities, of which $750 million may be issued under each credit facility as letters of credit. As of March 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $175 million.

We have a $627 million 3-year credit agreement. Under the facility, we may issue letters of credit. As of March 31, 2010, $477 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the bank conduits and receives cash. Prior to January 1, 2010, this transaction constituted a sale of receivables in accordance with the accounting guidance for "Transfers and Servicing," allowing the receivables to be removed from our Condensed Consolidated Balance Sheet. See "ASU 2009-16 'Transfers and Servicing' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and will be accounted for as financing. AEP Credit continues to service the receivables. We entered into these securitized transactions to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended March 31, 2010 (in millions)
Credit Losses Related to Securitized Accounts Receivable	$ 4

	March 31, 2010	December 31, 2009
	(in millions)	
Total Principal Outstanding	$ 651	$ 656
Derecognized Accounts Receivable	-	631
Delinquent Securitized Accounts Receivable	37	29

As of March 31, 2010, AEP Credit's bad debt reserves related to the securitized accounts receivable was $24 million. Customer accounts receivable retained and securitized for the electric operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

12. COMPANY-WIDE STAFFING AND BUDGET REVIEW

In April 2010, we began initiatives to decrease both labor and non-labor expenses 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 seeking 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.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

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

First Quarter of 2009		$ 74
Changes in Gross Margin:		
Retail Margins	42	
Off-system Sales	3	
Transmission Revenues	1	
Other	(1)	
Total Change in Gross Margin		45
Total Expenses and Other:		
Other Operation and Maintenance	(32)	
Depreciation and Amortization	(7)	
Taxes Other Than Income Taxes	(2)	
Other Income	(2)	
Carrying Costs Income	2	
Interest Expense	(2)	
Total Expenses and Other		(43)
Income Tax Expense		(6)
First Quarter of 2010		$ 70

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 $42 million primarily due to the following:
  - A $52 million increase in rate relief primarily due to the impact of the Virginia interim rate increase implemented in December 2009, subject to refund, an increase in the recovery of E&R costs in Virginia and an increase in the recovery of construction financing costs in West Virginia.
  - A $20 million increase in residential usage primarily due to a 17% increase in heating degree days.

  These increases were partially offset by:
  - A $19 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
  - An $11 million decrease in industrial sales primarily due to suspended operations by APCo's largest customer, Century Aluminum.

- Margins from Off-system Sales increased $3 million primarily due to higher physical sales volumes reflecting favorable generation availability, partially offset by lower trading and marketing margins.

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

- Other Operation and Maintenance expenses increased $32 million primarily due to the following:
  - A $13 million increase in employee benefit expenses.
  - An $8 million increase related to the reduction of a 2009 regulatory asset for the over-recovery of transmission costs.
  - A $7 million increase in maintenance expenses resulting primarily from a planned outage at the Amos Plant and snow storm damage restoration.
- Depreciation and Amortization expenses increased $7 million primarily due to a greater depreciation base resulting from environmental upgrades at the Amos and Mountaineer Plants and the amortization of carrying charges and depreciation expenses being collected through the Virginia E&R surcharges.
- Income Tax Expense increased $6 million primarily due to the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

FINANCIAL CONDITION

LIQUIDITY

APCo participates in the Utility Money Pool, which provides access to AEP's liquidity. APCo has $150 million of Senior Unsecured Notes and $50 million of Pollution Control Bonds that will mature in 2010. APCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of liquidity.

Credit Ratings

APCo's credit ratings as of March 31, 2010 were as follows:

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

Moody's, S&P and Fitch have APCo on stable outlook. Downgrades from any of the rating agencies could increase APCo's borrowing costs.

CASH FLOW

Cash flows for the three months ended March 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,006	$ 1,996
Cash Flows from (Used for):		
Operating Activities	178,522	(29,207)
Investing Activities	(167,978)	(220,590)
Financing Activities	(10,308)	250,355

Net Increase in Cash and Cash Equivalents		236		558
Cash and Cash Equivalents at End of Period	$	2,242	$	2,554

Operating Activities

Net Cash Flows from Operating Activities were $179 million in 2010. APCo produced Net Income of $70 million during the period and a noncash expense item of $77 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $98 million outflow from Accounts Payable was primarily due to the placement of FGD equipment into service at the Amos Plant and decreased purchases of energy from the system pool. The $81 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The $41 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory and a decrease in the average cost per ton.

Net Cash Flows Used for Operating Activities were $29 million in 2009. APCo produced Net Income of $74 million during the period and had noncash expense items of $80 million for Deferred Income Taxes and $70 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $116 million cash outflow from Accounts Payable was primarily due to APCo’s provision for revenue refund of $77 million which was paid in the first quarter 2009 to the AEP West companies as part of the FERC’s recent order on the SIA. The $71 million change in Fuel Over/Under-Recovery, Net resulted in a net under-recovery of fuel cost in both Virginia and West Virginia.

Investing Activities

Net Cash Flows Used for Investing Activities during 2010 and 2009 were $168 million and $221 million, respectively. Construction expenditures of $167 million and $221 million in 2010 and 2009, respectively, were primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. Environmental upgrades primarily include the installation of FGD equipment at the Amos and Mountaineer Plants.

Financing Activities

Net Cash Flows Used for Financing Activities were $10 million in 2010. APCo had a net increase of $118 million in borrowings from the Utility Money Pool. APCo retired $100 million of Notes Payable - Affiliated and issued $17.5 million of Pollution Control Bonds in 2010. In addition, APCo paid $44 million in dividends on common stock.

Net Cash Flows from Financing Activities were $250 million in 2009. APCo issued $350 million of Senior Unsecured Notes in March 2009. APCo had a net decrease of $74 million in borrowings from the Utility Money Pool.

Long-term debt issuances, retirements and principal payments made during the first three months of 2010 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date

Pollution Control Bonds	$	17,500	4.625	2021

Retirements and Principal Payments

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Affiliated	$	100,000	4.708	2010
Land Note		4	13.718	2026

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in "Cash Flow" above.

REGULATORY ACTIVITY

Virginia Regulatory Activity

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. The new 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 Regulatory Activity

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

In a 2009 proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. The order also indicated that it is in the best interests of West Virginia customers that the merger occurs as quickly as possible. Merger approvals from the WVPSC, Virginia SCC and the FERC are required. No merger approval filings have been made.

SIGNIFICANT FACTORS

REGULATORY ISSUES

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.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome will be or the timing and amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect APCo's net income, financial condition and cash flows.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 and pension and other postretirement benefits.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of risk management activities.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
REVENUES		
Electric Generation, Transmission and Distribution	$ 845,990	$ 727,959
Sales to AEP Affiliates	78,771	56,231
Other Revenues	1,862	1,839
TOTAL REVENUES	926,623	786,029
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	180,640	143,681
Purchased Electricity for Resale	63,683	75,816
Purchased Electricity from AEP Affiliates	267,502	197,124
Other Operation	90,040	65,502
Maintenance	63,110	55,910
Depreciation and Amortization	77,430	69,995
Taxes Other Than Income Taxes	26,280	24,103
TOTAL EXPENSES	768,685	632,131
OPERATING INCOME	157,938	153,898
Other Income (Expense):		
Interest Income	291	382
Carrying Costs Income	5,764	4,083
Allowance for Equity Funds Used During Construction	1,163	2,653
Interest Expense	(51,727)	(49,705)
INCOME BEFORE INCOME TAX EXPENSE	113,429	111,311
Income Tax Expense	43,147	36,904
NET INCOME	70,282	74,407
Preferred Stock Dividend Requirements Including Capital Stock Expense	225	225
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 70,057	$ 74,182

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 260,458	$ 1,225,292	$ 951,066	$ (60,225)	$ 2,376,591
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		26	(25)		1
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,356,392
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $945				1,756	1,756
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $661				1,226	1,226
NET INCOME			74,407		74,407
TOTAL COMPREHENSIVE INCOME					77,389
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2009	$ 260,458	$ 1,225,318	$ 1,005,248	$ (57,243)	$ 2,433,781
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 260,458	$ 1,475,393	$ 1,085,980	$ (50,254)	$ 2,771,577
Common Stock Dividends			(44,000)		(44,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		27	(25)		2
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,727,379
COMPREHENSIVE INCOME					

Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				(1,746)	(1,746)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $562				1,043	1,043
NET INCOME			70,282		70,282
TOTAL COMPREHENSIVE INCOME					69,579
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$ 260,458	$ 1,475,420	$ 1,112,037	$ (50,957)	$ 2,796,958

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,242	$ 2,006
Accounts Receivable:		
Customers	150,827	150,285
Affiliated Companies	68,831	135,686
Accrued Unbilled Revenues	56,777	68,971
Miscellaneous	4,447	6,690
Allowance for Uncollectible Accounts	(5,471)	(5,408)
Total Accounts Receivable	275,411	356,224
Fuel	303,191	343,261
Materials and Supplies	87,591	88,575
Risk Management Assets	78,529	67,956
Accrued Tax Benefits	156,821	180,708
Regulatory Asset for Under-Recovered Fuel Costs	54,829	78,685
Prepayments and Other Current Assets	42,336	36,293
TOTAL CURRENT ASSETS	1,000,950	1,153,708
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	4,603,157	4,284,361
Transmission	1,821,829	1,813,777
Distribution	2,671,245	2,642,479
Other Property, Plant and Equipment	353,552	329,497
Construction Work in Progress	437,070	730,099
Total Property, Plant and Equipment	9,886,853	9,800,213
Accumulated Depreciation and Amortization	2,777,628	2,751,443
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,109,225	7,048,770
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,457,796	1,433,791
Long-term Risk Management Assets	65,847	47,141
Deferred Charges and Other Noncurrent Assets	130,954	113,003
TOTAL OTHER NONCURRENT ASSETS	1,654,597	1,593,935
TOTAL ASSETS	$ 9,764,772	$ 9,796,413

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 347,425	$ 229,546
Accounts Payable:		
General	185,339	291,240
Affiliated Companies	100,994	157,640
Long-term Debt Due Within One Year – Nonaffiliated	200,020	200,019
Long-term Debt Due Within One Year – Affiliated	-	100,000
Risk Management Liabilities	35,161	25,792
Customer Deposits	59,202	57,578
Deferred Income Taxes	66,669	68,706
Accrued Taxes	65,810	65,241
Accrued Interest	69,667	58,962
Other Current Liabilities	80,507	95,292
TOTAL CURRENT LIABILITIES	1,210,794	1,350,016
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,211,224	3,177,287
Long-term Risk Management Liabilities	30,388	20,364
Deferred Income Taxes	1,478,387	1,439,884
Regulatory Liabilities and Deferred Investment Tax Credits	534,661	526,546
Employee Benefits and Pension Obligations	310,417	312,873
Deferred Credits and Other Noncurrent Liabilities	174,196	180,114
TOTAL NONCURRENT LIABILITIES	5,739,273	5,657,068
TOTAL LIABILITIES	6,950,067	7,007,084
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,747	17,752
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,475,420	1,475,393
Retained Earnings	1,112,037	1,085,980
Accumulated Other Comprehensive Income (Loss)	(50,957)	(50,254)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,796,958	2,771,577
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 9,764,772	$ 9,796,413

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$ 70,282	$ 74,407
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	77,430	69,995
Deferred Income Taxes	19,121	80,375
Carrying Costs Income	(5,764)	(4,083)
Allowance for Equity Funds Used During Construction	(1,163)	(2,653)
Mark-to-Market of Risk Management Contracts	(12,977)	(9,433)
Fuel Over/Under-Recovery, Net	(11,804)	(70,837)
Change in Other Noncurrent Assets	11,082	(7,737)
Change in Other Noncurrent Liabilities	(2,568)	3,098
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	80,813	64,045
Fuel, Materials and Supplies	41,054	(39,266)
Accounts Payable	(97,732)	(115,697)
Accrued Taxes, Net	24,150	(41,201)
Other Current Assets	(4,250)	(16,033)
Other Current Liabilities	(9,152)	(14,187)
Net Cash Flows from (Used for) Operating Activities	178,522	(29,207)
INVESTING ACTIVITIES		
Construction Expenditures	(167,412)	(221,053)
Other Investing Activities	(566)	463
Net Cash Flows Used for Investing Activities	(167,978)	(220,590)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	17,376	345,814
Change in Advances from Affiliates, Net	117,879	(74,407)
Retirement of Long-term Debt – Nonaffiliated	(5)	(4)
Retirement of Long-term Debt – Affiliated	(100,000)	-
Retirement of Cumulative Preferred Stock	(4)	-
Principal Payments for Capital Lease Obligations	(1,790)	(848)
Dividends Paid on Common Stock	(44,000)	(20,000)
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Other Financing Activities	436	-
Net Cash Flows from (Used for) Financing Activities	(10,308)	250,355
Net Increase in Cash and Cash Equivalents	236	558
Cash and Cash Equivalents at Beginning of Period	2,006	1,996
Cash and Cash Equivalents at End of Period	$ 2,242	$ 2,554

SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	38,971	$	49,390
Net Cash Paid (Received) for Income Taxes		-		(2,683)
Noncash Acquisitions Under Capital Leases		20,369		151
Construction Expenditures Included in Accounts Payable at March 31,		43,262		88,405

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

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

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

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

First Quarter of 2009		$ 49
Changes in Gross Margin:		
Retail Margins	3	
Off-system Sales	4	
Total Change in Gross Margin		7
Total Expenses and Other:		
Other Operation and Maintenance	6	
Depreciation and Amortization	(3)	
Taxes Other Than Income Taxes	(2)	
Interest Expense	(1)	
Total Expenses and Other		-
Income Tax Expense		(4)
First Quarter of 2010		$ 52

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 $3 million due to:
  - A $22 million increase related to the implementation of higher rates set by the Ohio ESP.
  - A $5 million increase in fuel margins.

  These increases were partially offset by:
  - A $14 million decrease as a result of the elimination of Restructuring Transition Charge (RTC) revenues with the implementation of CSPCo's ESP.
  - A $4 million decrease as a result of the loss of the City of Westerville as a dedicated customer to Off-system Sales. These sales are shared by the members of the AEP Power Pool.
  - A $4 million decrease in commercial and industrial sales primarily due to reduced usage.
- Margins from Off-system Sales increased $4 million primarily due to higher physical sales volumes reflecting favorable generation availability.

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

- Other Operation and Maintenance expenses decreased $6 million primarily due to:
  - An $8 million decrease related to a 2009 obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of CSPCo's ESP. See "Ohio Electric Security Plan Filings" section of Note 3.
  - A $3 million decrease in overhead distribution line expenses primarily due to ice and wind storms in the first quarter of 2009, partially offset by increased vegetation management activities.
  - A $3 million decrease in removal costs primarily related to work performed at the Conesville and Darby Plants.

  These decreases were partially offset by:
  - A $4 million increase in recoverable customer account expenses due to increased Universal Service Fund surcharge rates for customers who qualify for payment assistance.
  - A $3 million increase in employee-related expenses.
- Depreciation and Amortization increased $3 million primarily due to projects at the Conesville Plant that were completed and placed in service in November 2009.
- Taxes Other Than Income Taxes increased $2 million due to increases in property taxes.
- Income Tax Expense increased $4 million primarily due to an increase in pretax book income, other book/tax differences accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Ohio Electric Security Plan Filing

During 2009, the PUCO issued an order that modified and approved CSPCo's ESP which established rates through 2011. The order also limits rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% 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.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, CSPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome will be or the timing and amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect CSPCo's net income, financial condition and cash flows.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 and pension and other postretirement benefits.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of risk management activities.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
REVENUES		
Electric Generation, Transmission and Distribution	$ 501,019	$ 460,922
Sales to AEP Affiliates	15,832	10,206
Other Revenues	588	608
TOTAL REVENUES	517,439	471,736
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	114,441	70,944
Purchased Electricity for Resale	19,645	29,838
Purchased Electricity from AEP Affiliates	98,799	93,092
Other Operation	77,326	76,088
Maintenance	24,283	31,014
Depreciation and Amortization	37,487	34,945
Taxes Other Than Income Taxes	47,057	45,282
TOTAL EXPENSES	419,038	381,203
OPERATING INCOME	98,401	90,533
Other Income (Expense):		
Interest Income	142	240
Carrying Costs Income	2,221	1,689
Allowance for Equity Funds Used During Construction	921	1,300
Interest Expense	(21,784)	(20,793)
INCOME BEFORE INCOME TAX EXPENSE	79,901	72,969
Income Tax Expense	28,251	24,111
NET INCOME	51,650	48,858
Capital Stock Expense	39	39
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 51,611	$ 48,819

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 41,026	$ 580,506	$ 674,758	$ (51,025)	$ 1,245,265
Common Stock Dividends			(50,000)		(50,000)
Capital Stock Expense		39	(39)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,195,265
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $340				631	631
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $298				554	554
NET INCOME			48,858		48,858
TOTAL COMPREHENSIVE INCOME					50,043
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2009	$ 41,026	$ 580,545	$ 673,577	$ (49,840)	$ 1,245,308
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 41,026	$ 580,663	$ 788,139	$ (49,993)	$ 1,359,835
Common Stock Dividends			(31,250)		(31,250)
Capital Stock Expense		39	(39)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,328,585
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $555				(1,031)	(1,031)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $333				619	619

NET INCOME			51,650		51,650
TOTAL COMPREHENSIVE INCOME					51,238
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$ 41,026	$ 580,702	$ 808,500	$ (50,405)	$ 1,379,823

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,414	$ 1,096
Other Cash Deposits	5,860	16,150
Advances to Affiliates	37,818	-
Accounts Receivable:		
Customers	43,051	37,158
Affiliated Companies	14,766	28,555
Accrued Unbilled Revenues	12,078	11,845
Miscellaneous	4,812	4,164
Allowance for Uncollectible Accounts	(2,019)	(3,481)
Total Accounts Receivable	72,688	78,241
Fuel	83,463	74,158
Materials and Supplies	40,142	39,652
Emission Allowances	25,177	26,587
Risk Management Assets	44,362	34,343
Accrued Tax Benefits	9,517	29,273
Margin Deposits	18,971	14,874
Prepayments and Other Current Assets	14,101	6,349
TOTAL CURRENT ASSETS	353,513	320,723
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,648,128	2,641,860
Transmission	635,148	623,680
Distribution	1,748,245	1,745,559
Other Property, Plant and Equipment	201,250	189,315
Construction Work in Progress	144,328	155,081
Total Property, Plant and Equipment	5,377,099	5,355,495
Accumulated Depreciation and Amortization	1,861,973	1,838,840
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,515,126	3,516,655
OTHER NONCURRENT ASSETS		
Regulatory Assets	309,995	341,029
Long-term Risk Management Assets	37,264	23,882
Deferred Charges and Other Noncurrent Assets	128,009	147,217
TOTAL OTHER NONCURRENT ASSETS	475,268	512,128
TOTAL ASSETS	$ 4,343,907	$ 4,349,506

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 24,202
Accounts Payable:		
General	85,166	95,872
Affiliated Companies	52,427	81,338
Long-term Debt Due Within One Year – Nonaffiliated	150,000	150,000
Long-term Debt Due Within One Year – Affiliated	-	100,000
Risk Management Liabilities	19,407	13,052
Customer Deposits	29,021	27,911
Accrued Taxes	154,344	199,001
Accrued Interest	27,203	24,669
Other Current Liabilities	70,480	67,053
TOTAL CURRENT LIABILITIES	588,048	783,098
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,438,592	1,286,393
Long-term Risk Management Liabilities	17,200	10,313
Deferred Income Taxes	539,387	535,265
Regulatory Liabilities and Deferred Investment Tax Credits	177,639	174,671
Employee Benefits and Pension Obligations	132,317	133,968
Deferred Credits and Other Noncurrent Liabilities	70,901	65,963
TOTAL NONCURRENT LIABILITIES	2,376,036	2,206,573
TOTAL LIABILITIES	2,964,084	2,989,671
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,702	580,663
Retained Earnings	808,500	788,139
Accumulated Other Comprehensive Income (Loss)	(50,405)	(49,993)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,379,823	1,359,835
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 4,343,907	$ 4,349,506

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$ 51,650	$ 48,858
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	37,487	34,945
Deferred Income Taxes	8,327	38,945
Allowance for Equity Funds Used During Construction	(921)	(1,300)
Mark-to-Market of Risk Management Contracts	(11,609)	(3,204)
Property Taxes	24,131	22,262
Fuel Over/Under-Recovery, Net	26,139	(16,934)
Change in Other Noncurrent Assets	(4,994)	(8,551)
Change in Other Noncurrent Liabilities	(46)	13,410
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5,553	43,345
Fuel, Materials and Supplies	(9,795)	(19,854)
Accounts Payable	(22,402)	(81,080)
Accrued Taxes, Net	(24,444)	(57,623)
Other Current Assets	(428)	1,157
Other Current Liabilities	(1,619)	(9,817)
Net Cash Flows from Operating Activities	77,029	4,559
INVESTING ACTIVITIES		
Construction Expenditures	(42,906)	(67,831)
Change in Other Cash Deposits	10,290	11,093
Change in Advances to Affiliates, Net	(37,818)	-
Acquisitions of Assets	(190)	-
Proceeds from Sales of Assets	789	206
Net Cash Flows Used for Investing Activities	(69,835)	(56,532)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	149,625	-
Change in Advances from Affiliates, Net	(24,202)	102,871
Retirement of Long-term Debt – Affiliated	(100,000)	-
Principal Payments for Capital Lease Obligations	(1,120)	(674)
Dividends Paid on Common Stock	(31,250)	(50,000)
Other Financing Activities	71	-
Net Cash Flows from (Used for) Financing Activities	(6,876)	52,197
Net Increase in Cash and Cash Equivalents	318	224
Cash and Cash Equivalents at Beginning of Period	1,096	1,063
Cash and Cash Equivalents at End of Period	$ 1,414	$ 1,287

SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	18,631	$	31,229
Net Cash Paid for Income Taxes		-		387
Noncash Acquisitions Under Capital Leases		8,353		254
Construction Expenditures Included in Accounts Payable at March 31,		13,891		51,297

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

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

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

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

First Quarter of 2009		$ 81
Changes in Gross Margin:		
Retail Margins	35	
FERC Municipals and Cooperatives	(8)	
Off-system Sales	3	
Transmission Revenues	1	
Other	(55)	
Total Change in Gross Margin		(24)
Total Expenses and Other:		
Other Operation and Maintenance	(24)	
Depreciation and Amortization	(1)	
Other Income	1	
Interest Expense	(2)	
Total Expenses and Other		(26)
Income Tax Expense		14
First Quarter of 2010		$ 45

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 $35 million primarily due to the following:
  - A $12 million base rate increase primarily due to the approval of the Indiana base rate filing, effective March 2009.
  - A $10 million increase in capacity settlements under the Interconnection Agreement.
  - 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.
  - An $8 million increase in margins from industrial sales due to higher industrial usage reflecting an improvement in demand.

  These increases were partially offset by:
  - A $10 million decrease in other fuel margins.

- A $4 million increase in PJM charges.
- FERC Municipals and Cooperatives margins decreased $8 million due to a unit power sales agreement ending in December 2009.
- Margins from Off-system Sales increased $3 million primarily due to higher physical sales volumes reflecting favorable generation availability, partially offset by lower trading and marketing margins.
- Other revenues decreased $55 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.

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

- Other Operation and Maintenance expenses increased $24 million primarily due to the following:
  - A $13 million increase in administrative and general expenses for increased benefit and insurance costs.
  - A $4 million increase in steam production expense primarily due to deferral of NSR costs in 2009 included in a rate settlement.
  - A $3 million increase in transmission expense reflecting lower credits under the Transmission Agreement.
- Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income.

REGULATORY ACTIVITY

Michigan Regulatory Activity

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.

SIGNIFICANT FACTORS

REGULATORY ISSUES

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.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome will be or the timing and amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect I&M's net income, financial condition and cash flows.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 and pension and other postretirement benefits.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of risk management activities.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
REVENUES		
Electric Generation, Transmission and Distribution	$ 438,024	$ 421,927
Sales to AEP Affiliates	84,217	59,986
Other Revenues – Affiliated	27,966	30,740
Other Revenues – Nonaffiliated	2,849	54,391
TOTAL REVENUES	553,056	567,044
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	119,181	102,960
Purchased Electricity for Resale	29,767	38,361
Purchased Electricity from AEP Affiliates	82,250	79,978
Other Operation	130,681	109,460
Maintenance	48,444	46,274
Depreciation and Amortization	33,831	32,745
Taxes Other Than Income Taxes	21,032	20,696
TOTAL EXPENSES	465,186	430,474
OPERATING INCOME	87,870	136,570
Other Income (Expense):		
Interest Income	485	2,543
Allowance for Equity Funds Used During Construction	4,435	1,555
Interest Expense	(26,101)	(23,531)
INCOME BEFORE INCOME TAX EXPENSE	66,689	117,137
Income Tax Expense	21,631	36,185
NET INCOME	45,058	80,952
Preferred Stock Dividend Requirements	85	85
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 44,973	$ 80,867

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 56,584	$ 861,291	$ 538,637	$ (21,694)	$ 1,434,818
Common Stock Dividends			(24,500)		(24,500)
Preferred Stock Dividends			(85)		(85)
Gain on Reacquired Preferred Stock		1			1
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,410,234
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $463				859	859
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $111				207	207
NET INCOME			80,952		80,952
TOTAL COMPREHENSIVE INCOME					82,018
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2009	$ 56,584	$ 861,292	$ 595,004	$ (20,628)	$ 1,492,252
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 56,584	$ 981,292	$ 656,608	$ (21,701)	$ 1,672,783
Common Stock Dividends			(25,750)		(25,750)
Preferred Stock Dividends			(85)		(85)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,646,948
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					

Cash Flow Hedges, Net of Tax of $422				(784)	(784)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $117				218	218
NET INCOME			45,058		45,058
TOTAL COMPREHENSIVE INCOME					44,492
TOTAL COMMON SHAREHOLDER’S EQUITY – MARCH 31, 2010	$ 56,584	$ 981,292	$ 675,831	$ (22,267)	$ 1,691,440

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 994	$ 779
Advances to Affiliates	85,186	114,012
Accounts Receivable:		
Customers	61,564	71,120
Affiliated Companies	58,417	83,248
Accrued Unbilled Revenues	7,395	8,762
Miscellaneous	16,160	8,638
Allowance for Uncollectible Accounts	(2,111)	(2,265)
Total Accounts Receivable	141,425	169,503
Fuel	98,700	79,554
Materials and Supplies	164,265	164,439
Risk Management Assets	46,704	34,438
Accrued Tax Benefits	142,237	144,473
Deferred Cook Plant Fire Costs	143,071	134,322
Prepayments and Other Current Assets	30,810	29,395
TOTAL CURRENT ASSETS	853,392	870,915
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	3,650,607	3,634,215
Transmission	1,160,617	1,154,026
Distribution	1,373,381	1,360,553
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	783,596	755,132
Construction Work in Progress	297,681	278,278
Total Property, Plant and Equipment	7,265,882	7,182,204
Accumulated Depreciation, Depletion and Amortization	3,094,371	3,073,695
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,171,511	4,108,509
OTHER NONCURRENT ASSETS		
Regulatory Assets	525,685	496,464
Spent Nuclear Fuel and Decommissioning Trusts	1,433,012	1,391,919
Long-term Risk Management Assets	48,654	29,134
Deferred Charges and Other Noncurrent Assets	87,677	82,047
TOTAL OTHER NONCURRENT ASSETS	2,095,028	1,999,564
TOTAL ASSETS	$ 7,119,931	$ 6,978,988

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2010 and December 31, 2009
(Unaudited)

		2010		2009
CURRENT LIABILITIES		(in thousands)		
Accounts Payable:				
General	$	151,467	$	171,192
Affiliated Companies		52,146		61,315
Long-term Debt Due Within One Year – Nonaffiliated		37,544		37,544
Long-term Debt Due Within One Year – Affiliated		-		25,000
Risk Management Liabilities		19,423		13,436
Customer Deposits		28,927		27,711
Accrued Taxes		76,903		56,814
Obligations Under Capital Leases		27,327		25,065
Other Current Liabilities		209,788		154,433
TOTAL CURRENT LIABILITIES		603,525		572,510
NONCURRENT LIABILITIES				
Long-term Debt – Nonaffiliated		2,015,546		2,015,362
Long-term Risk Management Liabilities		17,306		10,386
Deferred Income Taxes		720,092		696,163
Regulatory Liabilities and Deferred Investment Tax Credits		799,892		756,845
Asset Retirement Obligations		911,918		894,746
Deferred Credits and Other Noncurrent Liabilities		352,135		352,116
TOTAL NONCURRENT LIABILITIES		4,816,889		4,725,618
TOTAL LIABILITIES		5,420,414		5,298,128
Cumulative Preferred Stock Not Subject to Mandatory Redemption		8,077		8,077
Rate Matters (Note 3)				
Commitments and Contingencies (Note 4)				
COMMON SHAREHOLDER'S EQUITY				
Common Stock – No Par Value:				
Authorized – 2,500,000 Shares				
Outstanding – 1,400,000 Shares		56,584		56,584
Paid-in Capital		981,292		981,292
Retained Earnings		675,831		656,608
Accumulated Other Comprehensive Income (Loss)		(22,267)		(21,701)
TOTAL COMMON SHAREHOLDER'S EQUITY		1,691,440		1,672,783
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$	7,119,931	$	6,978,988

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$ 45,058	$ 80,952
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	33,831	32,745
Deferred Income Taxes	18,442	56,889
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(20,025)	(7,851)
Allowance for Equity Funds Used During Construction	(4,435)	(1,555)
Mark-to-Market of Risk Management Contracts	(20,345)	(3,272)
Amortization of Nuclear Fuel	30,090	13,228
Fuel Over/Under-Recovery, Net	16,439	(5,709)
Change in Other Noncurrent Assets	(11,056)	(12,585)
Change in Other Noncurrent Liabilities	28,926	9,715
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	28,078	34,499
Fuel, Materials and Supplies	(18,972)	(2,036)
Accounts Payable	13,171	(68,603)
Accrued Taxes, Net	23,964	(1,224)
Other Current Assets	(13,044)	(18,527)
Other Current Liabilities	38,068	(26,733)
Net Cash Flows from Operating Activities	188,190	79,933
INVESTING ACTIVITIES		
Construction Expenditures	(104,796)	(92,814)
Change in Advances to Affiliates, Net	28,826	-
Purchases of Investment Securities	(247,632)	(178,407)
Sales of Investment Securities	232,078	158,086
Acquisitions of Nuclear Fuel	(37,616)	(75,670)
Other Investing Activities	500	10,757
Net Cash Flows Used for Investing Activities	(128,640)	(178,048)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	567,949
Issuance of Long-term Debt – Affiliated	-	25,000
Change in Advances from Affiliates, Net	-	(459,615)
Retirement of Long-term Debt – Affiliated	(25,000)	-
Retirement of Cumulative Preferred Stock	-	(2)
Principal Payments for Capital Lease Obligations	(8,524)	(10,377)
Dividends Paid on Common Stock	(25,750)	(24,500)
Dividends Paid on Cumulative Preferred Stock	(85)	(85)
Other Financing Activities	24	-

Net Cash Flows from (Used for) Financing Activities		(59,335)		98,370
Net Increase in Cash and Cash Equivalents		215		255
Cash and Cash Equivalents at Beginning of Period		779		728
Cash and Cash Equivalents at End of Period	$	994	$	983
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	30,056	$	35,231
Net Cash Paid (Received) for Income Taxes		-		(355)
Noncash Acquisitions Under Capital Leases		8,476		705
Construction Expenditures Included in Accounts Payable at March 31,		29,496		29,910
Acquisition of Nuclear Fuel Included in Accounts Payable at March 31,		2,705		17,016

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments, Guarantees and Contingencies	Note 4
Benefit Plans	Note 6
Business Segments	Note 7
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Fair Value Measurements	Note 9
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Financing Activities	Note 11
Company-wide Staffing and Budget Review	Note 12

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

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

First Quarter of 2009		$ 73
Changes in Gross Margin:		
Retail Margins	42	
Off-system Sales	5	
Other	(18)	
Total Change in Gross Margin		29
Total Expenses and Other:		
Other Operation and Maintenance	14	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	(2)	
Carrying Costs Income	3	
Interest Expense	(1)	
Total Expenses and Other		9
Income Tax Expense		(19)
First Quarter of 2010		$ 92

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 $42 million primarily due to the following:
  - A $24 million increase in capacity settlements under the Interconnection Agreement.
  - A $23 million increase primarily due to a $16 million increase related to the implementation of higher rates set by the Ohio ESP and $6 million of increased demand charges from WPCo effective January 2010.
  - A $12 million increase in fuel margins.

  These increases were partially offset by:
  - A $15 million decrease in retail sales primarily due to a decrease in residential and commercial usage.
- Margins from Off-system Sales increased $5 million primarily due to higher physical sales volumes reflecting favorable generating availability.
- Other revenues decreased $18 million primarily due to reduced gains on the sale of emission allowances.

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

- Other Operation and Maintenance expenses decreased $14 million primarily due to:
  - An $8 million decrease related to a 2009 obligation to contribute to the "Partnership with Ohio" fund for low income, at-risk customers ordered by the PUCO's March 2009 approval of OPCo's ESP.
  - A $7 million decrease from the reversal of an accrual for employee benefit expenses.
  - A $4 million decrease in rent expense as a result of the purchase of JMG in December 2009.

  These decreases were partially offset by:
  - A $3 million increase in recoverable customer account expenses due to increased Universal Service Fund surcharge rates for customers who qualify for payment assistance.
  - A $2 million increase in employee benefit expenses.
- Depreciation and Amortization increased $5 million primarily due to a $6 million increase from higher depreciable property balances as a result of environmental improvements placed in service and various other property additions, partially offset by a $1 million decrease due to distribution leasehold improvements being fully amortized in the fourth quarter of 2009.
- Interest expense increased $1 million primarily due to:
  - A $6 million decrease in the debt component of AFUDC primarily due to the Amos Plant FGD and precipitator upgrade going into service in March 2009.
  - A $5 million increase primarily due to an increase in interest expense from the issuance of long-term debt in September 2009.

  These increases were partially offset by:
  - An $8 million decrease in interest expense related to the reacquisition of JMG's bonds during the third quarter of 2009.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income and the tax treatment associated with the future reimbursement of Medicare Part D prescription drug benefits.

FINANCIAL CONDITION

LIQUIDITY

OPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. OPCo has $600 million of Senior Unsecured Notes and $79 million of Pollution Control Bonds that will mature in 2010. OPCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of liquidity.

Credit Ratings

OPCo's credit ratings as of March 31, 2010 were as follows:

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

Moody's, S&P and Fitch have OPCo on stable outlook. Downgrades from any of the rating agencies could increase OPCo's borrowing costs.

CASH FLOW

Cash flows for the three months ended March 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 1,984	$ 12,679
Cash Flows from (Used for):		
Operating Activities	251,324	(22,900)
Investing Activities	(258,305)	(156,584)
Financing Activities	6,150	180,174
Net Increase (Decrease) in Cash and Cash Equivalents	(831)	690
Cash and Cash Equivalents at End of Period	$ 1,153	$ 13,369

Operating Activities

Net Cash Flows from Operating Activities were $251 million in 2010. OPCo produced Net Income of $92 million during the period and noncash expense items of $89 million for Depreciation and Amortization, $41 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. Accounts Receivable, Net had a $62 million inflow primarily due to decreased sales to affiliates and settlement of allowance sales to affiliated companies. Fuel, Materials and Supplies had a $57 million inflow primarily due to a decrease in coal inventory deliveries. Accrued Taxes, Net had a $30 million outflow due to temporary timing differences of payments for property taxes partially offset by a decrease of federal income tax related accruals. The $38 million change in Fuel Over/Under-Recovery, Net reflects the deferral of fuel costs as a fuel clause was reactivated in 2009 under OPCo's ESP.

Net Cash Flows Used for Operating Activities were $23 million in 2009. OPCo produced Net Income of $73 million during the period and noncash expense items of $84 million for Depreciation and Amortization, $72 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital primarily relates to a number of items. Accounts Payable had a $95 million cash outflow primarily due to OPCo's provision for revenue refund of $62 million which was paid in the first quarter 2009 to the AEP West companies as part of the FERC's order on the SIA. Accrued Taxes, Net had a $79 million cash outflow due to a decrease of federal income tax related accruals and temporary timing differences of payments for property taxes. Fuel, Materials and Supplies had a $53 million cash outflow primarily due to an increase in coal inventory. Accounts Receivable, Net had a $40 million inflow due to timing differences of payments from customers and the receipt of final payment due to a coal contract amendment. The $65 million change in Fuel Over/Under Recovery, Net reflects the deferral of fuel costs as a fuel clause was reactivated in 2009 under OPCo's ESP.

Investing Activities

Net Cash Flows Used for Investing Activities in 2010 and 2009 were $258 million and $157 million, respectively. OPCo had a net increase of $179 million in loans to the Utility Money Pool in 2010. Construction Expenditures of $78 million and $163 million in 2010 and 2009, respectively, were primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and FGD projects at the Amos Plant.

Financing Activities

Net Cash Flows from Financing Activities were $6 million during 2010. OPCo issued $86 million of Pollution Control Bonds in March 2010. OPCo also paid $75 million in dividends on common stock.

Net Cash Flows from Financing Activities were $180 million in 2009 primarily due to a net increase of $186 million in borrowings from the Utility Money Pool.

Long-term debt issuances during the first three months of 2010 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	86,000	3.125	2043

Retirements

None

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end other than debt issuances discussed in “Cash Flow” above.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Ohio Electric Security Plan Filing

During 2009, the PUCO issued an order that modified and approved OPCo’s ESP which established rates through 2011. The order also limits rate increases 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.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome will be or the timing and amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect OPCo's net income, financial condition and cash flows.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 and pension and other postretirement benefits.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of risk management activities.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
REVENUES		
Electric Generation, Transmission and Distribution	$ 543,700	$ 524,686
Sales to AEP Affiliates	306,768	226,694
Other Revenues – Affiliated	6,574	7,488
Other Revenues – Nonaffiliated	4,231	3,847
TOTAL REVENUES	861,273	762,715
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	331,017	253,474
Purchased Electricity for Resale	38,890	52,269
Purchased Electricity from AEP Affiliates	22,191	16,742
Other Operation	89,156	99,598
Maintenance	56,231	60,040
Depreciation and Amortization	89,361	84,023
Taxes Other Than Income Taxes	53,084	51,492
TOTAL EXPENSES	679,930	617,638
OPERATING INCOME	181,343	145,077
Other Income (Expense):		
Interest Income	405	244
Carrying Costs Income	4,874	1,584
Allowance for Equity Funds Used During Construction	1,031	867
Interest Expense	(39,975)	(38,681)
INCOME BEFORE INCOME TAX EXPENSE	147,678	109,091
Income Tax Expense	55,775	36,482
NET INCOME	91,903	72,609
Less: Net Income Attributable to Noncontrolling Interest	-	463
NET INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	91,903	72,146
Less: Preferred Stock Dividend Requirements	183	183
EARNINGS ATTRIBUTABLE TO OPCo COMMON SHAREHOLDER	$ 91,720	$ 71,963

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	OPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2008	$ 321,201	$ 536,640	$ 1,697,962	$ (133,858)	$ 16,799	$ 2,438,744
Common Stock Dividends – Nonaffiliated					(463)	(463)
Preferred Stock Dividends			(183)			(183)
Other Changes in Equity					1,111	1,111
SUBTOTAL – EQUITY						2,439,209
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $570				1,058		1,058
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $855				1,588		1,588
NET INCOME			72,146		463	72,609
TOTAL COMPREHENSIVE INCOME						75,255
TOTAL EQUITY – MARCH 31, 2009	$ 321,201	$ 536,640	$ 1,769,925	$ (131,212)	$ 17,910	$ 2,514,464
TOTAL COMMON SHAREHOLDER'S EQUITY –DECEMBER 31, 2009	$ 321,201	$ 1,123,149	$ 1,908,803	$ (118,458)	$ -	$ 3,234,695
Common Stock Dividends			(75,287)			(75,287)
Preferred Stock Dividends			(183)			(183)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY						3,159,225

COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of $817				(1,517)		(1,517)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $949				1,762		1,762
NET INCOME			91,903			91,903
TOTAL COMPREHENSIVE INCOME						92,148
TOTAL COMMON SHAREHOLDER’S EQUITY –MARCH 31, 2010	$ 321,201	$ 1,123,149	$ 1,925,236	$ (118,213)	$ -	$ 3,251,373

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,153	$ 1,984
Advances to Affiliates	617,299	438,352
Accounts Receivable:		
Customers	64,895	60,711
Affiliated Companies	129,823	200,579
Accrued Unbilled Revenues	19,146	15,021
Miscellaneous	3,076	2,701
Allowance for Uncollectible Accounts	(2,668)	(2,665)
Total Accounts Receivable	214,272	276,347
Fuel	280,344	336,866
Materials and Supplies	114,976	115,486
Risk Management Assets	59,227	50,048
Accrued Tax Benefits	128,944	143,473
Prepayments and Other Current Assets	37,415	26,301
TOTAL CURRENT ASSETS	1,453,630	1,388,857
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	6,755,219	6,731,469
Transmission	1,184,514	1,166,557
Distribution	1,579,150	1,567,871
Other Property, Plant and Equipment	374,890	348,718
Construction Work in Progress	204,870	198,843
Total Property, Plant and Equipment	10,098,643	10,013,458
Accumulated Depreciation and Amortization	3,395,099	3,318,896
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,703,544	6,694,562
OTHER NONCURRENT ASSETS		
Regulatory Assets	795,135	742,905
Long-term Risk Management Assets	43,746	28,003
Deferred Charges and Other Noncurrent Assets	162,378	184,812
TOTAL OTHER NONCURRENT ASSETS	1,001,259	955,720
TOTAL ASSETS	$ 9,158,433	$ 9,039,139

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in thousands)	
Accounts Payable:		
General	$ 166,683	$ 182,848
Affiliated Companies	81,706	92,766
Long-term Debt Due Within One Year – Nonaffiliated	679,450	679,450
Risk Management Liabilities	29,456	24,391
Customer Deposits	23,238	22,409
Accrued Taxes	159,132	203,335
Accrued Interest	48,674	46,431
Other Current Liabilities	109,626	104,889
TOTAL CURRENT LIABILITIES	1,297,965	1,356,519
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,449,659	2,363,055
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	20,353	12,510
Deferred Income Taxes	1,345,173	1,302,939
Regulatory Liabilities and Deferred Investment Tax Credits	137,116	128,187
Employee Benefits and Pension Obligations	259,072	269,485
Deferred Credits and Other Noncurrent Liabilities	181,095	155,122
TOTAL NONCURRENT LIABILITIES	4,592,468	4,431,298
TOTAL LIABILITIES	5,890,433	5,787,817
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,627	16,627
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,123,149	1,123,149
Retained Earnings	1,925,236	1,908,803
Accumulated Other Comprehensive Income (Loss)	(118,213)	(118,458)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,251,373	3,234,695
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 9,158,433	$ 9,039,139

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$ 91,903	$ 72,609
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	89,361	84,023
Deferred Income Taxes	41,462	71,740
Carrying Costs Income	(4,874)	(1,584)
Allowance for Equity Funds Used During Construction	(1,031)	(867)
Mark-to-Market of Risk Management Contracts	(13,704)	(7,117)
Property Taxes	24,242	21,527
Fuel Over/Under-Recovery, Net	(38,025)	(65,192)
Change in Other Noncurrent Assets	(5,008)	1,669
Change in Other Noncurrent Liabilities	(1,741)	19,318
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	62,075	39,518
Fuel, Materials and Supplies	57,032	(52,588)
Accounts Payable	(10,190)	(95,306)
Customer Deposits	829	2,073
Accrued Taxes, Net	(30,082)	(78,533)
Accrued Interest	2,243	(8,311)
Other Current Assets	(8,331)	(15,394)
Other Current Liabilities	(4,837)	(10,485)
Net Cash Flows from (Used for) Operating Activities	251,324	(22,900)
INVESTING ACTIVITIES		
Construction Expenditures	(78,398)	(163,263)
Change in Advances to Affiliates, Net	(178,947)	-
Acquisitions of Assets	(823)	-
Proceeds from Sales of Assets	2,047	2,796
Other Investing Activities	(2,184)	3,883
Net Cash Flows Used for Investing Activities	(258,305)	(156,584)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	85,487	-
Change in Advances from Affiliates, Net	-	186,279
Retirement of Long-term Debt – Nonaffiliated	-	(4,500)
Principal Payments for Capital Lease Obligations	(2,101)	(1,316)
Dividends Paid on Common Stock – Nonaffiliated	-	(463)
Dividends Paid on Common Stock – Affiliated	(75,287)	-
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Other Financing Activities	(1,766)	357
Net Cash Flows from Financing Activities	6,150	180,174

Net Increase (Decrease) in Cash and Cash Equivalents		(831)		690
Cash and Cash Equivalents at Beginning of Period		1,984		12,679
Cash and Cash Equivalents at End of Period	$	1,153	$	13,369
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	36,243	$	64,554
Net Cash Paid for Income Taxes		-		2,337
Noncash Acquisitions Under Capital Leases		22,559		157
Construction Expenditures Included in Accounts Payable at March 31,		12,894		15,767

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

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

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

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

First Quarter of 2009		$ 6
Changes in Gross Margin:		
Retail Margins (a)	11	
Off-system Sales	1	
Transmission Revenues	2	
Other	1	
Total Change in Gross Margin		15
Total Expenses and Other:		
Other Operation and Maintenance	(16)	
Depreciation and Amortization	1	
Other Income	(1)	
Interest Expense	(2)	
Total Expenses and Other		(18)
Income Tax Expense		1
First Quarter of 2010		$ 4

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

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

- Retail Margins increased $11 million primarily due to base rate increases.
- Transmission Revenues increased $2 million primarily due to higher rates in the SPP region.

Total Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $16 million primarily due to the following:
  - A $7 million increase in employee-related expenses.
  - A $6 million increase in plant maintenance expense primarily resulting from the 2009 deferral of generation maintenance expenses as a result of PSO's base rate case.
- Interest Expense increased $2 million primarily due to an increase in long-term borrowings in the last half of 2009.

FINANCIAL CONDITION

LIQUIDITY

PSO participates in the Utility Money Pool, which provides access to AEP's liquidity. PSO relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of liquidity.

Credit Ratings

PSO's credit ratings as of March 31, 2010 were as follows:

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

Moody's, S&P and Fitch have PSO on stable outlook. Downgrades from any of the rating agencies could increase PSO's borrowing costs.

CASH FLOW

Cash flows for the three months ended March 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 796	$ 1,345
Cash Flows from (Used for):		
Operating Activities	(60,332)	103,803
Investing Activities	5,380	(59,145)
Financing Activities	55,082	(44,726)
Net Increase (Decrease) in Cash and Cash Equivalents	130	(68)
Cash and Cash Equivalents at End of Period	$ 926	$ 1,277

Operating Activities

Net Cash Flows Used for Operating Activities were $60 million in 2010. PSO produced Net Income of $4 million during the period and had noncash expense items of $27 million for Depreciation and Amortization and $21 million for Deferred Income Taxes, offset by a $28 million increase in the deferral of Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a $15 million inflow from Accounts Payable primarily due to timing differences for payments to affiliates and payments of items accrued at December 31, 2009. The $82 million outflow from Fuel Over/Under-Recovery, Net was primarily due to refunding to customers the prior month's fuel over-recoveries through lower fuel factors.

Net Cash Flows from Operating Activities were $104 million in 2009. PSO produced Net Income of $6 million during the period and had a noncash expense item of $28 million for Depreciation and Amortization, offset by a $28 million increase in the deferral of Property Taxes and a $14 million increase in Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $93 million inflow from Accounts Receivable, Net was primarily due to receiving the SIA refund from the AEP East companies and lower customer receivables. The $37 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The $29 million outflow from Accounts Payable was primarily due to timing differences for payments to affiliates and payment of items accrued at December 31, 2008. The $37 million inflow from Fuel Over/Under-Recovery, Net was primarily due to lower fuel costs.

Investing Activities

Net Cash Flows from Investing Activities were $5 million during 2010 and Net Cash Flows Used for Investing Activities were $59 million during 2009. Construction Expenditures of $55 million and $52 million in 2010 and 2009, respectively, were primarily related to projects for improved generation, transmission and distribution service reliability. During 2010, PSO had a net decrease of $63 million in loans to the Utility Money Pool. During 2009, PSO had a net increase of $7 million in loans to the Utility Money Pool.

Financing Activities

Net Cash Flows from Financing Activities were $55 million during 2010. PSO had a net increase of $69 million in borrowings from the Utility Money Pool. This inflow was partially offset by $13 million paid in dividends on common stock.

Net Cash Flows Used for Financing Activities were $45 million during 2009. PSO had a net decrease of $70 million in borrowings from the Utility Money Pool. PSO issued $34 million of Pollution Control Bonds in February 2009. In addition, PSO paid $7 million in dividends on common stock.

PSO did not have any long-term debt issuances or retirements during the first three months of 2010.

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end.

REGULATORY ACTIVITY

Oklahoma Regulatory Activity

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.

SIGNIFICANT FACTORS

LITIGATION AND ENVIRONMENTAL ISSUES

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

Commitments, Guarantees and Contingencies in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect PSO's net income, financial condition and cash flows.

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QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of risk management activities.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
REVENUES		
Electric Generation, Transmission and Distribution	$ 228,551	$ 278,771
Sales to AEP Affiliates	8,670	15,823
Other Revenues	534	693
TOTAL REVENUES	237,755	295,287
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	40,972	119,399
Purchased Electricity for Resale	44,980	44,425
Purchased Electricity from AEP Affiliates	10,992	5,915
Other Operation	49,662	39,545
Maintenance	30,939	25,430
Depreciation and Amortization	27,288	27,950
Taxes Other Than Income Taxes	10,300	10,751
TOTAL EXPENSES	215,133	273,415
OPERATING INCOME	22,622	21,872
Other Income (Expense):		
Interest Income	182	648
Carrying Costs Income	867	1,711
Allowance for Equity Funds Used During Construction	247	170
Interest Expense	(17,363)	(14,805)
INCOME BEFORE INCOME TAX EXPENSE	6,555	9,596
Income Tax Expense	2,416	3,558
NET INCOME	4,139	6,038
Preferred Stock Dividend Requirements	53	53
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 4,086	$ 5,985

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 157,230	$ 340,016	$ 251,704	$ (704)	$ 748,246
Common Stock Dividends			(7,250)		(7,250)
Preferred Stock Dividends			(53)		(53)
Other Changes in Common Shareholder's Equity		4,214	(4,214)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					740,943
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $12				22	22
NET INCOME			6,038		6,038
TOTAL COMPREHENSIVE INCOME					6,060
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2009	$ 157,230	$ 344,230	$ 246,225	$ (682)	$ 747,003
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 157,230	$ 364,231	$ 290,880	$ (599)	$ 811,742
Common Stock Dividends			(12,687)		(12,687)
Preferred Stock Dividends			(53)		(53)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					799,002
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $62				116	116
NET INCOME			4,139		4,139
TOTAL COMPREHENSIVE INCOME					4,255

TOTAL COMMON SHAREHOLDER’S EQUITY – MARCH 31, 2010	$	157,230	$	364,231	$	282,279	$	(483)	$	803,257

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 926	$ 796
Advances to Affiliates	-	62,695
Accounts Receivable:		
Customers	32,961	38,239
Affiliated Companies	58,353	59,096
Miscellaneous	7,461	7,242
Allowance for Uncollectible Accounts	(128)	(304)
Total Accounts Receivable	98,647	104,273
Fuel	21,608	20,892
Materials and Supplies	46,560	44,914
Risk Management Assets	3,263	2,376
Deferred Income Tax Benefits	14,312	26,335
Accrued Tax Benefits	32,860	15,291
Regulatory Asset for Under-Recovered Fuel Costs	31,025	-
Prepayments and Other Current Assets	11,311	9,139
TOTAL CURRENT ASSETS	260,512	286,711
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,304,060	1,300,069
Transmission	633,864	617,291
Distribution	1,627,977	1,596,355
Other Property, Plant and Equipment	244,558	228,705
Construction Work in Progress	81,462	67,138
Total Property, Plant and Equipment	3,891,921	3,809,558
Accumulated Depreciation and Amortization	1,234,393	1,220,177
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,657,528	2,589,381
OTHER NONCURRENT ASSETS		
Regulatory Assets	276,679	279,185
Long-term Risk Management Assets	157	50
Deferred Charges and Other Noncurrent Assets	40,328	13,880
TOTAL OTHER NONCURRENT ASSETS	317,164	293,115
TOTAL ASSETS	$ 3,235,204	$ 3,169,207

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 68,743	$ -
Accounts Payable:		
General	101,867	76,895
Affiliated Companies	78,260	71,099
Risk Management Liabilities	536	2,579
Customer Deposits	41,603	42,002
Accrued Taxes	37,591	19,471
Regulatory Liability for Over-Recovered Fuel Costs	-	51,087
Other Current Liabilities	56,929	60,905
TOTAL CURRENT LIABILITIES	385,529	324,038
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	968,808	968,121
Long-term Risk Management Liabilities	117	144
Deferred Income Taxes	602,506	588,768
Regulatory Liabilities and Deferred Investment Tax Credits	317,573	326,931
Employee Benefits and Pension Obligations	108,101	107,748
Deferred Credits and Other Noncurrent Liabilities	44,055	36,457
TOTAL NONCURRENT LIABILITIES	2,041,160	2,028,169
TOTAL LIABILITIES	2,426,689	2,352,207
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,258	5,258
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	364,231	364,231
Retained Earnings	282,279	290,880
Accumulated Other Comprehensive Income (Loss)	(483)	(599)
TOTAL COMMON SHAREHOLDER'S EQUITY	803,257	811,742
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,235,204	$ 3,169,207

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$ 4,139	$ 6,038
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	27,288	27,950
Deferred Income Taxes	20,526	(13,835)
Carrying Costs Income	(867)	(1,711)
Allowance for Equity Funds Used During Construction	(247)	(170)
Mark-to-Market of Risk Management Contracts	(2,959)	(562)
Property Taxes	(27,797)	(28,050)
Fuel Over/Under-Recovery, Net	(82,112)	36,650
Change in Other Noncurrent Assets	(10,473)	429
Change in Other Noncurrent Liabilities	1,764	(1,879)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5,626	92,561
Fuel, Materials and Supplies	(2,362)	1,386
Accounts Payable	15,235	(28,623)
Accrued Taxes, Net	1,152	36,694
Other Current Assets	(2,108)	(3,511)
Other Current Liabilities	(7,137)	(19,564)
Net Cash Flows from (Used for) Operating Activities	(60,332)	103,803
INVESTING ACTIVITIES		
Construction Expenditures	(54,837)	(52,368)
Change in Advances to Affiliates, Net	62,695	(7,009)
Other Investing Activities	(2,478)	232
Net Cash Flows from (Used for) Investing Activities	5,380	(59,145)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	33,283
Change in Advances from Affiliates, Net	68,743	(70,308)
Principal Payments for Capital Lease Obligations	(1,026)	(398)
Dividends Paid on Common Stock	(12,687)	(7,250)
Dividends Paid on Cumulative Preferred Stock	(53)	(53)
Other Financing Activities	105	-
Net Cash Flows from (Used for) Financing Activities	55,082	(44,726)
Net Increase (Decrease) in Cash and Cash Equivalents	130	(68)
Cash and Cash Equivalents at Beginning of Period	796	1,345
Cash and Cash Equivalents at End of Period	$ 926	$ 1,277
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 8,267	$ 29,174

Net Cash Paid (Received) for Income Taxes	(1,331)	391
Noncash Acquisitions Under Capital Leases	13,274	391
Construction Expenditures Included in Accounts Payable at March 31,	28,799	11,776

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

RESULTS OF OPERATIONS

First Quarter of 2010 Compared to First Quarter of 2009

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

First Quarter of 2009		$ 12
Changes in Gross Margin:		
Retail Margins (a)	18	
Off-system Sales	1	
Transmission Revenues	2	
Other	(11)	
Total Change in Gross Margin		10
Total Expenses and Other:		
Other Operation and Maintenance	5	
Depreciation and Amortization	3	
Taxes Other Than Income Taxes	(1)	
Other Income	9	
Interest Expense	(2)	
Equity Earnings of Unconsolidated Subsidiaries	1	
Total Expenses and Other		15
Income Tax Expense		(6)
First Quarter of 2010		$ 31

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

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

- Retail Margins increased $18 million primarily due to the following:
  - A $13 million increase in retail sales primarily due to favorable weather and slight increases in usage in the commercial and industrial classes.
  - A $3 million increase in base rates in Arkansas.
  - A $2 million increase in FERC wholesale and municipal revenue.
- Transmission Revenues increased $2 million primarily due to higher rates in the SPP region.
- Other revenues decreased $11 million resulting from the deconsolidation of SWEPCo's mining subsidiary, Dolet Hills Lignite Company, LLC (DHLC). Prior to the deconsolidation, SWEPCo recorded revenues from coal deliveries from DHLC to CLECO. SWEPCo prospectively adopted the "Consolidation" accounting guidance

effective January 1, 2010 and began accounting for DHLC under the equity method of accounting. The decreased revenue from coal deliveries was offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

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

- Other Operation and Maintenance expenses decreased $5 million primarily due to the following:
  - An $8 million decrease in expenses for mining operations from DHLC. The decreased expenses for mining operations were partially offset by a corresponding decrease in revenues as discussed above.

  This decrease was partially offset by:
  - A $2 million gain on sale of property during the first quarter of 2009 related to the sale of percentage ownership of the Turk Plant to nonaffiliated companies who exercised their participation options.
- Depreciation and Amortization expenses decreased $3 million primarily due to lower Arkansas depreciation resulting from the Arkansas Base Rate Filing and the deconsolidation of DHLC.
- Other Income increased $9 million primarily due to an increase in AFUDC equity as a result of construction at the Turk Plant and Stall Unit and the reapplication of “Regulated Operations” accounting guidance for the generation portion of Texas’ retail jurisdiction effective the second quarter of 2009.
- Interest Expense increased $2 million primarily due to increased long-term debt outstanding and capital leases, partially offset by an increase in the debt component of AFUDC due to generation projects at the Turk Plant and Stall Unit.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income, partially offset by changes in certain book/tax differences accounted for on a flow-through basis.

FINANCIAL CONDITION

LIQUIDITY

SWEPCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. SWEPCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section for additional discussion of liquidity.

Credit Ratings

SWEPCo’s credit ratings as of March 31, 2010 were as follows:

	Moody’s	S&P	Fitch
Senior Unsecured Debt	Baa3	BBB	BBB+

Moody’s and S&P have SWEPCo on stable outlook. Fitch has SWEPCo on negative outlook. Downgrades from any of the rating agencies could increase SWEPCo’s borrowing costs.

CASH FLOW

Cash flows for the three months ended March 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	

Cash and Cash Equivalents at Beginning of Period	$	1,661	$	1,910
Cash Flows from (Used for):				
Operating Activities		(21,572)		93,470
Investing Activities		(277,945)		(103,382)
Financing Activities		299,536		9,739
Net Increase (Decrease) in Cash and Cash Equivalents		19		(173)
Cash and Cash Equivalents at End of Period	$	1,680	$	1,737

Operating Activities

Net Cash Flows Used for Operating Activities were $22 million in 2010. SWEPCo produced Net Income of $31 million during the period and had a noncash expense item of $33 million for Depreciation and Amortization, offset by a $29 million increase in the deferral of Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $46 million outflow from Accounts Payable was primarily due to timing differences for payments of items accrued at December 31, 2009. The $39 million inflow from Accrued Taxes, Net was the result of an increase in accruals related to property tax. The $17 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in coal inventory and a decrease in the average cost per ton. The $16 million outflow from Accrued Interest was primarily due to the timing of interest payments in relation to the accruals for payments.

Net Cash Flows from Operating Activities were $93 million in 2009. SWEPCo produced Net Income of $12 million during the period and had a noncash expense item of $37 million for Depreciation and Amortization, offset by a $30 million increase in the deferral of Property Taxes and $27 million increase in Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The $95 million inflow from Accounts Receivable, Net was primarily due to the receipt of payment for SIA from the AEP East companies. The $59 million inflow from Accrued Taxes, Net was the result of increased accruals related to income and property taxes. The $50 million outflow from Other Current Liabilities was due to a decrease in checks outstanding, a refund to wholesale customers for the SIA and payments of employee-related expenses. The $20 million outflow from Accrued Interest was due to increased long-term debt outstanding as well as the timing of interest payments in relation to the accruals for payments. The $27 million inflow from Fuel Over/Under-Recovery, Net was the result of a decrease in fuel costs in relation to the recovery of these costs from customers.

Investing Activities

Net Cash Flows Used for Investing Activities during 2010 and 2009 were $278 million and $103 million, respectively. Construction Expenditures of $89 million and $170 million in 2010 and 2009, respectively, were primarily related to generation projects at the Turk Plant and Stall Unit. During 2010, SWEPCo increased loans to the Utility Money Pool by $187 million. During 2009, SWEPCo increased loans to the Utility Money Pool by $38 million. These outflows in 2009 were partially offset by $104 million in proceeds from sales of assets primarily relating to the sale of a portion of Turk Plant to joint owners.

Financing Activities

Net Cash Flows from Financing Activities were $300 million during 2010 related to a $350 million issuance of Senior Unsecured Notes and a $54 million issuance of Pollution Control Bonds. These increases were partially offset by a $54 million retirement of Pollution Control Bonds and a $50 million retirement of Notes Payable – Affiliated.

Net Cash Flows from Financing Activities were $10 million during 2009. SWEPCo received capital contributions from the Parent of $18 million and had a net decrease of $3 million in borrowings from the Utility Money Pool.

Long-term debt issuances and retirements during the first three months of 2010 were:

Issuances

Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$ 350,000	6.20	2040
Pollution Control Bonds	53,500	3.25	2015

Retirements

Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Notes Payable – Affiliated	$ 50,000	4.45	2010
Pollution Control Bonds	53,500	Variable	2019

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end other than debt issuances and retirements discussed in "Cash Flow" above.

REGULATORY ACTIVITY

Texas Regulatory Activity

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 also allows SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

SIGNIFICANT FACTORS

REGULATORY ISSUES

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.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual outcome will be or the timing and amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss amount can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect SWEPCo's net income, financial condition and cash flows.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 and pension and other postretirement benefits.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” for a discussion of risk management activities.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
REVENUES		
Electric Generation, Transmission and Distribution	$ 333,078	$ 302,383
Sales to AEP Affiliates	9,333	8,344
Lignite Revenues – Nonaffiliated	-	10,720
Other Revenues	393	355
TOTAL REVENUES	342,804	321,802
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	122,888	126,315
Purchased Electricity for Resale	41,886	24,397
Purchased Electricity from AEP Affiliates	9,752	13,010
Other Operation	58,253	54,204
Maintenance	17,419	26,702
Depreciation and Amortization	33,243	36,792
Taxes Other Than Income Taxes	15,895	15,389
TOTAL EXPENSES	299,336	296,809
OPERATING INCOME	43,468	24,993
Other Income (Expense):		
Interest Income	79	454
Allowance for Equity Funds Used During Construction	15,517	6,405
Interest Expense	(18,544)	(16,299)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	40,520	15,553
Income Tax Expense	10,156	3,853
Equity Earnings of Unconsolidated Subsidiaries	719	-
NET INCOME	31,083	11,700
Less: Net Income Attributable to Noncontrolling Interest	1,151	1,137
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	29,932	10,563
Less: Preferred Stock Dividend Requirements	57	57
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 29,875	$ 10,506

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2008	$ 135,660	$ 530,003	$ 615,110	$ (32,120)	$ 276	$ 1,248,929
Capital Contribution from Parent		17,500				17,500
Common Stock Dividends – Nonaffiliated					(1,115)	(1,115)
Preferred Stock Dividends			(57)			(57)
Other Changes in Equity		2,476	(2,476)			-
SUBTOTAL – EQUITY						1,265,257
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $51				95		95
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $243				451		451
NET INCOME			10,563		1,137	11,700
TOTAL COMPREHENSIVE INCOME						12,246
TOTAL EQUITY – MARCH 31, 2009	$ 135,660	$ 549,979	$ 623,140	$ (31,574)	$ 298	$ 1,277,503
TOTAL EQUITY – DECEMBER 31, 2009	$ 135,660	$ 674,979	$ 726,478	$ (12,991)	$ 31	$ 1,524,157
Common Stock Dividends – Nonaffiliated					(809)	(809)
Preferred Stock Dividends			(57)			(57)
SUBTOTAL – EQUITY						1,523,291

COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $42				88		88
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $127				235		235
NET INCOME			29,932		1,151	31,083
TOTAL COMPREHENSIVE INCOME						31,406
TOTAL EQUITY – MARCH 31, 2010	$ 135,660	$ 674,979	$ 756,353	$ (12,668)	$ 373	$ 1,554,697

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,680	$ 1,661
Advances to Affiliates	238,817	34,883
Accounts Receivable:		
Customers	31,172	46,657
Affiliated Companies	25,390	19,542
Miscellaneous	15,376	9,952
Allowance for Uncollectible Accounts	(1)	(64)
Total Accounts Receivable	71,937	76,087
Fuel (March 31, 2010 amount includes $31,636 related to Sabine)	99,740	121,453
Materials and Supplies	45,987	54,484
Risk Management Assets	2,055	3,049
Deferred Income Tax Benefits	12,731	13,820
Accrued Tax Benefits	10,203	16,164
Regulatory Asset for Under-Recovered Fuel Costs	10,291	1,639
Prepayments and Other Current Assets	25,251	20,503
TOTAL CURRENT ASSETS	518,692	343,743
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	1,837,260	1,837,318
Transmission	875,469	870,069
Distribution	1,457,777	1,447,559
Other Property, Plant and Equipment (March 31, 2010 amount includes $229,220 related to Sabine)	638,983	733,310
Construction Work in Progress	1,253,122	1,176,639
Total Property, Plant and Equipment	6,062,611	6,064,895
Accumulated Depreciation and Amortization (March 31, 2010 amount includes $88,067 related to Sabine)	2,049,962	2,086,333
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,012,649	3,978,562
OTHER NONCURRENT ASSETS		
Regulatory Assets	283,964	268,165
Long-term Risk Management Assets	244	84
Deferred Charges and Other Noncurrent Assets	91,196	49,479
TOTAL OTHER NONCURRENT ASSETS	375,404	317,728
TOTAL ASSETS	$ 4,906,745	$ 4,640,033

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2010 and December 31, 2009
(Unaudited)

	2010	2009
CURRENT LIABILITIES	(in thousands)	
Accounts Payable:		
General	$ 115,639	$ 160,870
Affiliated Companies	58,288	59,818
Short-term Debt – Nonaffiliated	13,218	6,890
Long-term Debt Due Within One Year – Nonaffiliated	-	4,406
Long-term Debt Due Within One Year – Affiliated	-	50,000
Risk Management Liabilities	989	844
Customer Deposits	41,815	41,269
Accrued Taxes	54,966	24,720
Accrued Interest	17,661	33,179
Obligations Under Capital Leases	12,670	14,617
Regulatory Liability for Over-Recovered Fuel Costs	12,852	13,762
Provision for SIA Refund	21,003	19,307
Other Current Liabilities	40,891	71,781
TOTAL CURRENT LIABILITIES	389,992	501,463
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,769,331	1,419,747
Long-term Risk Management Liabilities	632	221
Deferred Income Taxes	498,283	485,936
Regulatory Liabilities and Deferred Investment Tax Credits	346,091	333,935
Asset Retirement Obligations	48,732	60,562
Employee Benefits and Pension Obligations	123,616	125,956
Obligations Under Capital Leases	119,562	134,044
Deferred Credits and Other Noncurrent Liabilities	51,112	49,315
TOTAL NONCURRENT LIABILITIES	2,957,359	2,609,716
TOTAL LIABILITIES	3,347,351	3,111,179
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,697	4,697
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	674,979	674,979
Retained Earnings	756,353	726,478

Accumulated Other Comprehensive Income (Loss)		(12,668)		(12,991)
TOTAL COMMON SHAREHOLDER’S EQUITY		1,554,324		1,524,126
Noncontrolling Interest		373		31
TOTAL EQUITY		1,554,697		1,524,157
TOTAL LIABILITIES AND EQUITY	$	4,906,745	$	4,640,033

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$ 31,083	$ 11,700
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	33,243	36,792
Deferred Income Taxes	477	(27,042)
Allowance for Equity Funds Used During Construction	(15,517)	(6,405)
Mark-to-Market of Risk Management Contracts	1,324	(752)
Property Taxes	(28,569)	(29,792)
Fuel Over/Under-Recovery, Net	(9,565)	26,786
Change in Other Noncurrent Assets	409	6,230
Change in Other Noncurrent Liabilities	3,779	331
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(5,975)	94,646
Fuel, Materials and Supplies	17,008	(4,775)
Accounts Payable	(46,408)	(2,717)
Accrued Taxes, Net	38,552	58,794
Accrued Interest	(15,512)	(20,160)
Other Current Assets	(4,310)	326
Other Current Liabilities	(21,591)	(50,492)
Net Cash Flows from (Used for) Operating Activities	(21,572)	93,470
INVESTING ACTIVITIES		
Construction Expenditures	(88,731)	(169,603)
Change in Advances to Affiliates, Net	(187,000)	(37,649)
Proceeds from Sales of Assets	174	104,824
Other Investing Activities	(2,388)	(954)
Net Cash Flows Used for Investing Activities	(277,945)	(103,382)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	17,500
Issuance of Long-term Debt – Nonaffiliated	399,650	(15)
Borrowings from Revolving Credit Facilities	23,743	27,435
Change in Advances from Affiliates, Net	-	(2,526)
Retirement of Long-term Debt – Nonaffiliated	(53,500)	(1,101)
Retirement of Long-term Debt – Affiliated	(50,000)	-
Repayments to Revolving Credit Facilities	(17,415)	(28,048)
Principal Payments for Capital Lease Obligations	(2,858)	(2,334)
Dividends Paid on Common Stock – Nonaffiliated	(809)	(1,115)
Dividends Paid on Cumulative Preferred Stock	(57)	(57)
Other Financing Activities	782	-
Net Cash Flows from Financing Activities	299,536	9,739

Net Increase (Decrease) in Cash and Cash Equivalents		19		(173)
Cash and Cash Equivalents at Beginning of Period		1,661		1,910
Cash and Cash Equivalents at End of Period	$	1,680	$	1,737
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	31,789	$	51,573
Net Cash Received for Income Taxes		(1,062)		(1,117)
Noncash Acquisitions Under Capital Leases		169		1,568
Construction Expenditures Included in Accounts Payable at March 31,		71,395		72,331

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

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

INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. The net income for the three months March 31, 2010 is not necessarily indicative of results that may be expected for the year ending December 31, 2010. The condensed financial statements are unaudited and should be read in conjunction with the audited 2009 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2009 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 they are the primary beneficiary of a VIE, each Registrant Subsidiary considers factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required. Also, see "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

SWEPCo is currently the primary beneficiary of Sabine. As of January 1, 2010, SWEPCo is no longer the primary beneficiary of DHLC as defined by new accounting guidance for "Variable Interest Entities." I&M is currently the primary beneficiary of DCC Fuel LLC (DCC Fuel). APCo, CSPCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and CSPCo each hold a significant variable interest in AEGCo. SWEPCo holds a significant variable interest in 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 SWEPCo's Condensed Consolidated Balance Sheets.

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 2009 were $13 million and $11 million, respectively. See the table below for the classification of DHLC assets and liabilities on SWEPCo's Condensed Consolidated Balance Sheet at December 31, 2009 as well as SWEPCo's 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 SWEPCo's 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.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
March 31, 2010
(in millions)

ASSETS	Sabine
Current Assets	$ 51
Net Property, Plant and Equipment	146
Other Noncurrent Assets	34
Total Assets	$ 231
LIABILITIES AND EQUITY	
Current Liabilities	$ 35
Noncurrent Liabilities	196
Equity	-
Total Liabilities and Equity	$ 231

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

ASSETS	Sabine	DHLC
Current Assets	$ 51	$ 8
Net Property, Plant and Equipment	149	44
Other Noncurrent Assets	35	11
Total Assets	$ 235	$ 63
LIABILITIES AND EQUITY		
Current Liabilities	$ 36	$ 17
Noncurrent Liabilities	199	38
Equity	-	8
Total Liabilities and Equity	$ 235	$ 63

SWEPCo's investment in DHLC was:

	March 31, 2010	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)	
Capital Contribution from Parent	$ 7	$ 7
Retained Earnings	1	1
SWEPCo's Guarantee of Debt	-	44
Total Investment in DHLC	$ 8	$ 52

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 I&M's control of DCC Fuel, management has concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital lease is eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's Condensed Consolidated Balance Sheets.

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

INDIANA MICHIGAN POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITY
March 31, 2010 and December 31, 2009
(in millions)

	DCC Fuel	
ASSETS	2010	2009
Current Assets	$ 56	$ 47
Net Property, Plant and Equipment	77	89
Other Noncurrent Assets	49	57
Total Assets	$ 182	$ 193
LIABILITIES AND EQUITY		
Current Liabilities	$ 41	$ 39
Noncurrent Liabilities	141	154
Equity	-	-
Total Liabilities and Equity	$ 182	$ 193

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. No AEP subsidiary has provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations by cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP's subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. All Registrant Subsidiaries are considered to have a significant interest in the variability in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, no Registrant Subsidiary has control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

Company	Three Months Ended March 31, 2010	2009
	(in millions)	
APCo	$ 59	$ 50
CSPCo	35	29
I&M	34	29
OPCo	49	41
PSO	24	21
SWEPCo	35	29

The carrying amount and classification of variable interest in AEPSC's accounts payable as of March 31, 2010 and December 31, 2009 are as follows:

	2010		2009	
	As Reported in the Balance Sheet	Maximum Exposure	As Reported in the Balance Sheet	Maximum Exposure
	(in millions)			
APCo	$ 23	$ 23	$ 23	$ 23
CSPCo	15	15	13	13
I&M	14	14	13	13
OPCo	20	20	18	18
PSO	9	9	9	9
SWEPCo	14	14	14	14

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. In May 2007, AEGCo began leasing the Lawrenceburg Generating Station to CSPCo. AEP guarantees all the debt obligations of AEGCo. I&M and CSPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and CSPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. Due to AEP management's control over AEGCo no subsidiary of AEP is the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to I&M, CSPCo and KPCo, this financing would be provided by AEP. See "Rockport Lease" section of Note 13 in the 2009 Annual Report for additional information regarding AEGCo's lease.

Total billings from AEGCo are as follows:

	Three Months Ended March 31, 2010	2009
	(in millions)	
CSPCo	$ 15	$ 17

I&M	56	63

The carrying amount and classification of variable interest in AEGCo's accounts payable as of March 31, 2010 and December 31, 2009 are as follows:

	March 31, 2010		December 31, 2009	
	As Reported in the Consolidated Balance Sheet	Maximum Exposure	As Reported in the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
CSPCo	$ 6	$ 6	$ 6	$ 6
I&M	18	18	23	23

Related Party Transactions

SWEPCo Lignite Purchases from DHLC

Effective January 1, 2010, SWEPCo deconsolidated DHLC due to the adoption of new accounting guidance. See "ASU 2009-17 'Consolidations' " section of Note 2. DHLC sells 50% of its lignite mining output to SWEPCo and the other 50% to CLECO. SWEPCo purchased $12.9 million of lignite from DHLC and recorded these costs in Fuel on its Condensed Consolidated Balance Sheet at March 31, 2010.

AEP Power Pool Purchases from OVEC

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale expenses on the respective income statements. The following table shows the amounts recorded for the three months ended March 31, 2010:

	Three Months Ended March 31, 2010	
Company	Reported in Revenues	Reported in Expenses
	(in thousands)	
APCo	$ (2,895)	$ 2,194
CSPCo	(1,576)	1,148
I&M	(1,589)	1,158
OPCo	(1,816)	1,330

Adjustments to Reported Cash Flows

In the Financing Activities section of SWEPCo's Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2009, SWEPCo corrected the presentation of borrowings on lines of credit of $28 million from Change in Short-term Debt, Net to Borrowings from Revolving Credit Facilities. SWEPCo also corrected the presentation of repayments on lines of credit of $28 million for the three months ended March 31, 2009 to Repayments to Revolving Credit Facilities from Change in Short-term Debt, Net. The correction to present borrowings and repayments on lines of credit on a gross basis was not material to SWEPCo's financial statements and had no impact on SWEPCo's previously reported net income, changes in shareholder's equity, financial position or net cash flows from financing activities.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of final pronouncements that impact the Registrant Subsidiaries' financial statements.

Pronouncement Adopted During The First Quarter of 2010

The following standard was effective during the first quarter of 2010. Consequently, its impact is reflected in the financial statements. The following paragraphs discuss its impact.

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.

The Registrant Subsidiaries adopted the prospective provisions of ASU 2009-17 effective January 1, 2010. This standard required separate presentation of material consolidated VIEs' assets and liabilities on the balance sheets. Upon adoption, SWEPCo deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, SWEPCo reports DHLC using the equity method of accounting.

3. RATE MATTERS

As discussed in the 2009 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 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

	APCo		I&M	
	March 31, 2010	December 31, 2009	March 31, 2010	December 31, 2009
Noncurrent Regulatory Assets (excluding fuel)	(in thousands)		(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:				
Regulatory Assets Currently Not Earning a Return				
	$ 111,461	$ 110,665	$ -	$ -

Mountaineer Carbon Capture and Storage Project				
Virginia Environmental Rate Adjustment Clause	27,232	25,311	-	-
Virginia Transmission Rate Adjustment Clause	21,088	26,184	-	-
Special Rate Mechanism for Century Aluminum	12,474	12,422	-	-
Deferred Wind Power Costs	10,581	5,372	-	-
Deferred PJM Fees	-	-	6,597	6,254
Total Regulatory Assets Not Yet Being Recovered	$ 182,836	$ 179,954	$ 6,597	$ 6,254

	CSPCo		OPCo	
	March 31, 2010	December 31, 2009	March 31, 2010	December 31, 2009
Noncurrent Regulatory Assets (excluding fuel)	(in thousands)		(in thousands)	
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	$ 28,994	$ 28,781	$ 28,494	$ 28,330
Line Extension Carrying Costs	28,379	26,590	17,530	16,278
Storm Related Costs	17,014	17,014	9,794	9,794
Acquisition of Monongahela Power	10,706	10,282	-	-
Regulatory Assets Currently Not Earning a Return				
Peak Demand Reduction/Energy Efficiency	5,796	4,071	5,713	4,007
Total Regulatory Assets Not Yet Being Recovered	$ 90,889	$ 86,738	$ 61,531	$ 58,409

	PSO		SWEPCo	
	March 31, 2010	December 31, 2009	March 31, 2010	December 31, 2009
Noncurrent Regulatory Assets (excluding fuel)	(in thousands)		(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:				
Regulatory Assets Currently Not Earning a Return				
Storm Related Costs	$ 11,329	$ -	$ -	$ -

Asset Retirement Obligation	-	-	521	471
Total Regulatory Assets Not Yet Being Recovered	$ 11,329	$ -	$ 521	$ 471

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. 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 March 31, 2010 were $10 million and $345 million for CSPCo and OPCo, respectively, excluding $1 million and $13 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 another 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). The SEET 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 would be returned to customers. The PUCO staff recommended that the SEET be calculated on an individual company basis and not on a combined CSPCo/OPCo basis and that off-system sales margins be included in the earnings test. It is unclear at this time whether the FAC phase-in deferral credits will be included in the earnings test. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets until they are collected, assuming there are excessive earnings in that year. In April 2010, the PUCO heard arguments related to various SEET issues including the treatment of the FAC deferrals. The PUCO's decision on the SEET methodology is not expected to be finalized until a SEET filing is made by CSPCo and OPCo related to 2009 earnings and the PUCO issues an order thereon. In April 2010, CSPCo and OPCo filed a request with the PUCO to delay their SEET filing until July 2010. As a result, 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.

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 effective from January 2009 through September 2009. In January 2009, the PUCO approved the application. 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 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 balance. 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 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised several issues including (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 days 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.

As of March 31, 2010, CSPCo and OPCo have incurred $21 million and $12 million, respectively, in EDR costs. Of these costs, CSPCo and OPCo have collected $8 million and $6 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $13 million and $6 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. Management cannot predict the amounts CSPCo and OPCo will defer for future recovery through the EDR. 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 related to environmental investments in 2009. CSPCo's and OPCo's proposed initial rider would recover $29 million and $37 million, respectively, from July 2010 through December 2011 for carrying costs for 2009 through 2011. If approved, the implementation of the rider will likely not impact cash flows, but will impact the ESP phase-in plan deferrals associated with the FAC since this rider is within 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. 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 $24 million collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

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% 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. As of March 31, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $777 million of expenditures (including AFUDC and capitalized interest, and related transmission costs of $35 million). As of March 31, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $459 million (including related transmission costs of $7 million). SWEPCo's share of the contractual construction commitments is $337 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of March 31, 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). Following an appeal by certain intervenors, the Arkansas Court of Appeals issued a unanimous decision that, if upheld by the Arkansas Supreme Court, would reverse the APSC's grant of the CECPN. The Arkansas Court of Appeals concluded that SWEPCo's need for base load capacity, the construction and financing of the Turk Plant and the proposed transmission facilities' construction and location should have been considered by the APSC in a single docket instead of separate dockets. The Arkansas Supreme Court granted petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals' decision. The Court heard oral arguments in April 2010. A decision from the Arkansas Supreme Court is pending.

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 CO_2 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 in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed the Texas District Court decision.

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 (ADEQ) and commenced construction at the site. In January 2010, 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 of the APCEC's decision 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.

Management believes that SWEPCo's planning, certification and construction of the Turk Plant has been in material compliance with all applicable laws and regulations. Further, management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if 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 reduce future net income and cash flows and impact financial condition.

Stall Unit

SWEPCo is constructing 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 Stall Unit is currently estimated to cost $431 million, including $51 million of AFUDC, and is expected to be in service in mid-2010. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs.

As of March 31, 2010, SWEPCo has capitalized construction costs of $402 million, including AFUDC, and has contractual construction commitments of an additional $17 million. If the final cost of the Stall Unit were to exceed the $445 million cost cap, the APSC or LPSC could disallow their jurisdictional allocation of construction costs in excess of the caps and thereby reduce future net income and cash flows and impact financial condition.

Louisiana Fuel Adjustment Clause Audit

Consultants for the LPSC issued their audit report of SWEPCo's Louisiana retail FAC. Various recommendations were contained within the audit report including two recommendations that might result in a financial impact that could be material for SWEPCo. The first recommendation is that SWEPCo should provide the variable operation and maintenance and SO2 allowance costs that were included in SWEPCo's purchased power costs and that those costs should be disallowed from 2003 until the effective date of the LPSC's audit order. The second recommendation is that the LPSC should discontinue SWEPCo's tiered sharing mechanism related to off-system sales margins on a prospective basis. In addition, the audit report contained a recommendation that SWEPCo should reflect the SIA refunds as reductions in the Louisiana FAC rates as soon as possible, including interest through the date the refunds are reflected in the FAC. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters." Management is unable to predict how the LPSC will rule on the recommendations in the audit report and its financial statement impact on net income, cash flows and financial condition.

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.

2008 Formula Rate Filing

In April 2008, SWEPCo filed its first formula rate filing under an approved three-year formula rate plan (FRP). SWEPCo requested an increase in its annual Louisiana retail rates of $11 million to be effective in August 2008 in order to earn the approved formula return on common equity of 10.565%. In August 2008, as provided by the FRP, SWEPCo implemented the FRP rates, subject to refund. During 2009, SWEPCo recorded a provision for refund of approximately $1 million after reaching a settlement in principle with intervenors. SWEPCo is currently working with the settlement parties to prepare a written agreement to be filed with the LPSC. If a refund is required, it could reduce future net income and cash flows and impact financial condition.

2009 Formula Rate Filing

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional $4 million effective in August 2009 pursuant to the approved FRP. SWEPCo implemented the FRP rate increase as filed in August 2009, subject to refund. In October 2009, consultants for the LPSC objected to certain components of SWEPCo's FRP calculation. The consultants also recommended refunding the SIA through SWEPCo's FRP. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters." SWEPCo will continue to work with the LPSC regarding the issues raised in their objection. SWEPCo believes the rates as filed are in compliance with the FRP methodology previously approved by the LPSC. If the LPSC disagrees with SWEPCo, it could result in refunds which would reduce future net income and cash flows and impact financial condition.

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. 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. The enacted legislation also stated that depending on the revenue awarded, a refund of interim rates may not be necessary. If a refund is required, it would reduce future net income and cash flows and impact financial condition.

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 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 March 31, 2010, APCo has recorded a noncurrent regulatory asset of $111 million consisting of $72 million in project costs and $39 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. 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 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.

APCo's Filings for an IGCC Plant

APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC power plant in Mason County, West Virginia. APCo also requested the Virginia SCC and the WVPSC to approve a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. The WVPSC granted APCo the CPCN and approved the requested cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order.

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism based upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on an unfavorable order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

Through March 31, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and in West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

APCo's 2009 Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo’s March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $320 million and a first-year increase of $112 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan. In March 2010, APCo filed its second-year request with the WVPSC to increase rates in July 2010 by $86 million. As of March 31, 2010, APCo’s ENEC under-recovery balance was $318 million which is included in noncurrent regulatory assets.

The September 2009 order also lowered annual coal cost projections by $27 million and deferred recovery of unrecovered ENEC deferrals related to price increases on certain renegotiated coal contracts. The WVPSC indicated that it would review the prudency of these additional costs in the next ENEC proceeding. As of March 31, 2010, APCo has deferred $23 million of unrecovered coal costs on the renegotiated coal contracts which is included in APCo’s $318 million ENEC regulatory asset and has recorded an additional $5 million in fuel inventory related to the renegotiated coal contracts, which is recorded in Fuel on the balance sheets. Although management believes the portion of its deferred ENEC under-recovery balance attributable to renegotiated coal contracts is probable of recovery, if the WVPSC were to disallow a portion of APCo’s deferred ENEC costs including any costs incurred in the future related to the renegotiated coal contracts, it could reduce future net income and cash flows and impact financial condition.

WPCo Merger with APCo

In a proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC, in November 2009, issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. The order also indicated that it is in the best interests of West Virginia customers that the merger occur as quickly as possible. Merger approvals from the WVPSC, Virginia SCC and the FERC are required. No merger approval filings have been made.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of $42 million of PSO fuel costs. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) has contended that PSO should not have collected the $42 million without specific OCC approval. As such, the OIEC contends that the OCC should require PSO to refund the $42 million it collected through its fuel clause. The OCC has heard the OIEC appeal and a decision is pending. In March 2010, PSO filed motions to advance this proceeding since the FERC has ruled on the allocation of off-system sales margins proceeding and PSO has refunded the additional margins to its retail customers. If the OCC were to order PSO to refund all or a part of the $42 million, it would reduce future net income and cash flows and impact financial condition.

2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudency review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins sharing decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. If the OCC were to issue an unfavorable decision, it would reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues based on a 10.5% return on equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. If the intervenors' appeals are successful, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

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

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately $53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4, Cook Unit 1 was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduce power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. A procedural schedule has been established for the subdocket with hearings expected to be held in November 2010.

Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition.

2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

Michigan Base Rate Filing

In January 2010, I&M filed for a $63 million increase in annual 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.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues. APCo's, CSPCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)
APCo	$ 70.2
CSPCo	38.8
I&M	41.3
OPCo	53.3

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

AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a refund of a portion or all of the unsettled SECA revenues. In December 2009, several parties filed a motion with the U.S. Court of Appeals to force the FERC to resolve the SECA issue.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. APCo's, CSPCo's, I&M's and OPCo's portions of the provision are as follows:

Company	(in millions)
APCo	$ 14.1
CSPCo	7.8
I&M	8.3
OPCo	10.7

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. The balance in the reserve for future settlements as of March 31, 2010 was $34 million. As of March 31, 2010 there were no in-process settlements. APCo's, CSPCo's, I&M's and OPCo's reserve balances at March 31, 2010 were:

Company	March 31, 2010 (in millions)
APCo	$ 10.7
CSPCo	5.9
I&M	6.3
OPCo	8.2

Based on the AEP East companies' settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the reserve is adequate to settle the remaining $108 million of contested SECA revenues. Management cannot predict the ultimate outcome of future settlement discussions or future proceedings at the FERC or court of appeals. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it would reduce future net income and cash flows and impact financial condition.

Allocation of Off-system Sales Margins – Affecting SWEPCo

The OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies.

In 2009, AEP made a compliance filing with the FERC and the AEP East companies refunded approximately $250 million to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their customers during the period June 2000 to March 2006. In 2008, the AEP West companies recorded a provision for refund reflecting the sharing. Refunds have been or are currently being returned to PSO's and SWEPCo's Texas, Arkansas and FERC customers. SWEPCo is working with the LPSC to determine how the FERC ordered refund will be made to its Louisiana retail customers. Consultants for the LPSC issued an audit report of SWEPCo's Louisiana retail fuel adjustment clause. Within this report, the consultants for the LPSC recommended that SWEPCo refund the SIA, including interest, through the fuel adjustment clause. See "Louisiana Fuel Adjustment Clause Audit" section within "SWEPCo Rate Matters." Other consultants for the LPSC recommended refunding the SIA through SWEPCo's formula rate plan. Management cannot predict if there will be any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding related future state regulatory proceedings is adequate.

Modification of the Transmission Agreement (TA) – Affecting APCo, CSPCo, I&M and OPCo

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. Settlement discussions are in progress. Once approved by the FERC, management is unable to predict whether the parties to the TA will experience regulatory lag and its effect on future net income and cash flows due to timing of the implementation of the modified TA by various state regulators.

PJM/MISO Market Flow Calculation Errors – Affecting APCo, CSPCo, I&M and OPCo

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO disputes PJM's methodology.

Settlement discussions between MISO and PJM have been unsuccessful, and as a result, in March 2010, MISO filed two related complaints against PJM at the FERC related to the above claim. MISO seeks to recover a total of approximately $145 million from PJM. Given that PJM passes its costs on to its members, if PJM is held liable for these damages, PJM members, including the AEP East companies, may be held responsible for a share of the refunds or payments PJM is directed to make to MISO. AEP has intervened and filed a protest to one complaint. Management believes that MISO's claims filed at the FERC are without merit and that PJM's right to recover from AEP and other members any damages awarded to MISO is limited. If the FERC orders a settlement above the AEP East companies' reserve related to their estimated portion of PJM additional costs, it could reduce future net income and cash flows and impact financial condition.

PJM Transmission Formula Rate Filing – Affecting APCo, CSPCo, I&M and OPCo

AEP filed an application with the FERC in July 2008 to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing sought to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. The FERC issued an order conditionally accepting AEP's proposed formula rate and delayed the requested October 2008 effective date for five months. AEP began settlement discussions with the intervenors and the FERC staff which resulted in a settlement that was filed with the FERC in April 2010.

The pending settlement results in a $51 million annual increase beginning in April 2009 for service as of March 2009, of which approximately $7 million is being collected from nonaffiliated customers within PJM. The remaining $44 million is being billed to the AEP East companies and is generally offset by compensation from PJM for use of the AEP East companies' transmission facilities so that net income is not directly affected.

The pending settlement also results in an additional $30 million increase for the first annual update of the formula rate, beginning in August 2009 for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM with the remaining $26 million being billed to the AEP East companies.

Under the formula, an annual update will be filed to be effective July 2010 and each year thereafter. Also, beginning with the July 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management expects the settlement will be approved by the FERC.

Transmission Agreement (TA) – Affecting APCo, CSPCo, I&M and OPCo

Certain transmission facilities placed in service in 1998 were inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was the Inez Station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was $7 million annually. Management does not believe that it is probable that a material retroactive rate adjustment will result from the omission. However, if a retroactive adjustment is required, it could reduce future net income and cash flows and impact financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2009 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits and debt service reserves. These LOCs were issued in the ordinary course of business under the two $1.5 billion 5-year credit facilities. The facilities are structured as two $1.5 billion credit facilities, of which $750 million may be issued under each credit facility as LOCs.

The Registrant Subsidiaries and certain other companies in the AEP System have a $627 million 3-year credit agreement. As of March 31, 2010, $477 million of LOCs were issued by Registrant Subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

As of March 31, 2010, the maximum future payments of the LOCs were as follows:

Company	Amount (in thousands)	Maturity	Borrower Sublimit
$1.5 billion LOCs:			
I&M	$ 300	March 2011	N/A
SWEPCo	4,448	December 2010	N/A
$627 million LOC:			
APCo	$ 232,292	June 2010 to November 2010	$ 300,000
I&M	77,886	May 2010	230,000
OPCo	166,899	June 2010	400,000

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036. A new study is in process to include new, expanded areas of the mine. As of March 31, 2010, SWEPCo has collected approximately $45 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $21 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $22 million is recorded in Asset Retirement Obligations on SWEPCo's Condensed Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to March 31, 2010, the Registrant Subsidiaries entered into sale agreements including indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

The Registrant Subsidiaries lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, the Registrant Subsidiaries will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008 and 2009, management signed new master lease agreements that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair value and the residual value guarantee. At March 31, 2010, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss (in thousands)
APCo	$ 236
CSPCo	57
I&M	405

OPCo	187
PSO	351
SWEPCo	322

Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $18 million for I&M and $21 million for SWEPCo for the remaining railcars as of March 31, 2010.

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

The Registrant Subsidiaries have other railcar lease arrangements that do not utilize this type of financing structure.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting CSPCo

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. Following a second liability trial in 2009, the jury again found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. Beckjord is operated by Duke Energy Ohio, Inc.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo’s Welsh Plant. In 2008, a consent decree resolved all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs’ attorneys’ fees and costs.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. Management is unable to predict the timing of any future action by the Federal EPA or the effect of such actions on net income, cash flows or financial condition.

Carbon Dioxide Public Nuisance Claims – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. The defendants' petition for rehearing was denied.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing and scheduled oral argument for May 24, 2010. The Registrant Subsidiaries were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint.

Management believes the actions are without merit and intends to continue to defend against the claims.

Alaskan Villages' Claims – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Management believes the action is without merit and intends to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting I&M

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

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M to take voluntary action necessary to prevent and/or mitigate public harm. In May 2008, I&M started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately $11 million of expense prior to January 1, 2010, $3 million of which I&M recorded in March 2009. As the remediation work is completed, I&M's cost may continue to increase. Management cannot predict the amount of additional cost, if any.

Amos Plant – Request to Show Cause – Affecting APCo and OPCo

In March 2010, APCo and OPCo received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting APCo and OPCo to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. Management indicated a willingness to engage in good faith negotiations and meet with representatives of the Federal EPA. APCo and OPCo have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable.

Defective Environmental Equipment – Affecting CSPCo and OPCo

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on units utilizing the jet bubbling reactor (JBR) technology. The following plants have been scheduled for the installation of the JBR technology or are currently utilizing JBR retrofits:

Plant Name	Plant Owners	JBRs Scheduled for Installation
Cardinal	OPCo/ Buckeye Power, Inc.	3
Conesville	CSPCo/Dayton Power and Light Company/ Duke Energy Ohio, Inc.	1
Muskingum River (a)	OPCo	1

(a) Contracts for the Muskingum River project have been temporarily suspended during the early development stage of the project.

The retrofits on two of the Cardinal Plant units and the Conesville Plant unit are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. Management intends to pursue contractual and other legal remedies if these issues with Black & Veatch are not resolved. If the AEP System is unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition.

NUCLEAR CONTINGENCIES – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

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 significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. 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 these 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.

I&M maintains property insurance through NEIL with a $1 million deductible. As of March 31, 2010, I&M recorded $143 million on its Condensed Consolidated Balance Sheet representing recoverable amounts under the property insurance policy. Through March 31, 2010, I&M received partial payments of $118 million from NEIL for the cost incurred to repair the property damage. In April 2010, I&M received a $45 million payment from NEIL.

I&M also maintained a separate accidental outage insurance policy with NEIL. In 2009, I&M recorded $185 million in revenues under this policy and reduced the cost of replacement power in customers’ bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Fort Wayne Lease – Affecting I&M

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

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In August 2009, the U.S. District Court upheld the arbitration board's decision. BNSF appealed the U.S. District Court's decision.

5. ACQUISITIONS

2010

Valley Electric Membership Corporation – Affecting SWEPCo

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). The current estimate of the purchase is $99 million, plus the assumption of certain liabilities, subject to adjustments at closing. Consummation of the transaction is subject to regulatory approval by the LPSC, the APSC, the Rural Utilities Service and the National Rural Utilities Cooperative Finance Corporation. In January 2010, the VEMCO members approved the transaction. In April 2010, a joint application between SWEPCo and VEMCO was filed with the LPSC. SWEPCo will seek recovery from Louisiana customers for all costs related to this acquisition. VEMCO services approximately 30,000 customers in Louisiana. SWEPCo expects to complete the transaction in the third quarter of 2010 upon receipt of regulatory and other approvals.

2009

None

6. BENEFIT PLANS

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the three months ended March 31, 2010 and 2009:

	Pension Plans Three Months Ended March 31,		Other Postretirement Benefit Plans Three Months Ended March 31,	
	2010	2009	2010	2009
	(in millions)			
Service Cost	$28	$26	$12	$10
Interest Cost	63	63	28	27
Expected Return on Plan Assets	(78)	(80)	(26)	(20)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	22	15	7	11
Net Periodic Benefit Cost	$35	$24	$28	$35

The following table provides the Registrant Subsidiaries' net periodic benefit cost for the plans for the three months ended March 31, 2010 and 2009:

	Pension Plans Three Months Ended March 31,		Other Postretirement Benefit Plans Three Months Ended March 31,	
	2010	2009	2010	2009
Company	(in thousands)			
APCo	$3,954	$2,615	$4,762	$6,058
CSPCo	1,486	688	2,062	2,638
I&M	5,035	3,485	3,464	4,358
OPCo	3,439	2,067	3,965	5,139
PSO	1,360	770	1,861	2,283
SWEPCo	1,774	1,208	1,893	2,363

7. BUSINESS SEGMENTS

The Registrant Subsidiaries have one reportable segment, an integrated electricity generation, transmission and distribution business. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for “Derivatives and Hedging.” Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of the Registrant Subsidiaries, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with long-term commodity derivative positions. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. From time to time, AEPSC, on behalf of the Registrant Subsidiaries, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as “Interest Rate and Foreign Currency.” The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP’s Board of Directors.

The following tables represent the gross notional volume of the Registrant Subsidiaries’ outstanding derivative contracts as of March 31, 2010 and December 31, 2009:

Notional Volume of Derivative Instruments
March 31, 2010
(in thousands)

Primary Risk Exposure	Unit of Measure	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
Commodity:							
Power	MWHs	156,031	88,273	90,380	101,589	15	18
Coal	Tons	11,112	6,616	4,928	31,865	5,597	8,075
Natural Gas	MMBtus	12,027	6,804	6,862	7,831	-	-
Heating Oil and Gasoline	Gallons	1,218	529	597	898	717	659
Interest Rate	USD	$ 12,703	$ 7,198	$ 7,198	$ 9,124	$ 705	$ 908
Interest Rate and Foreign Currency	USD	$ 150,000	$ -	$ -	$ -	$ -	$ 3,547

Notional Volume of Derivative Instruments
December 31, 2009
(in thousands)

Primary Risk Exposure	Unit of Measure	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
Commodity:							
Power	MWHs	191,121	96,828	99,265	112,745	10	12
Coal	Tons	11,347	5,615	5,150	23,631	5,936	6,790

Natural Gas	MMBtus	17,867	9,051	9,129	10,539	-	-
Heating Oil and Gasoline	Gallons	1,164	474	552	838	668	628
Interest Rate	USD	$ 21,054	$ 10,658	$ 10,716	$ 13,487	$ 1,137	$ 1,457
Interest Rate and Foreign Currency	USD	$ -	$ -	$ -	$ -	$ -	$ 3,798

Fair Value Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal, heating oil and natural gas (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries’ vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial gasoline and heating oil derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.” The Registrant Subsidiaries do not hedge all fuel price risk.

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

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP’s risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. The Registrant Subsidiaries do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2010 and December 31, 2009 balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	March 31, 2010		December 31, 2009	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
		(in thousands)		
APCo	$ 10,391	$ 51,936	$ 3,789	$ 31,806
CSPCo	5,879	29,408	1,920	16,108
I&M	5,929	29,520	1,936	16,222
OPCo	6,766	35,771	2,235	19,512
PSO	-	349	-	194
SWEPCo	-	572	-	305

The following tables represent the gross fair value impact of the Registrant Subsidiaries' derivative activity on the Balance Sheets as of March 31, 2010 and December 31, 2009:

Fair Value of Derivative Instruments
March 31, 2010

APCo

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 482,823	$ 4,882	$ 207	$ (409,383)	$ 78,529
	226,173	274	-	(160,600)	65,847

Long-term Risk Management Assets					
Total Assets	708,996	5,156	207	(569,983)	144,376
Current Risk Management Liabilities	458,322	8,189	908	(432,258)	35,161
Long-term Risk Management Liabilities	214,123	899	-	(184,634)	30,388
Total Liabilities	672,445	9,088	908	(616,892)	65,549
Total MTM Derivative Contract Net Assets (Liabilities)	$ 36,551	$ (3,932)	$ (701)	$ 46,909	$ 78,827

Fair Value of Derivative Instruments
December 31, 2009

APCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 332,764	$ 3,621	$ -	$ (268,429)	$ 67,956
Long-term Risk Management Assets	132,044	-	-	(84,903)	47,141
Total Assets	464,808	3,621	-	(353,332)	115,097
Current Risk Management Liabilities	309,639	5,084	-	(288,931)	25,792
Long-term Risk Management Liabilities	118,702	80	-	(98,418)	20,364
Total Liabilities	428,341	5,164	-	(387,349)	46,156
Total MTM Derivative Contract Net Assets (Liabilities)	$ 36,467	$ (1,543)	$ -	$ 34,017	$ 68,941

Fair Value of Derivative Instruments
March 31, 2010

CSPCo

Risk

Balance Sheet Location	Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 273,981	$ 2,726	$ -	$ (232,345)	$ 44,362
Long-term Risk Management Assets	128,131	155	-	(91,022)	37,264
Total Assets	402,112	2,881	-	(323,367)	81,626
Current Risk Management Liabilities	260,063	4,632	-	(245,288)	19,407
Long-term Risk Management Liabilities	121,335	508	-	(104,643)	17,200
Total Liabilities	381,398	5,140	-	(349,931)	36,607
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,714	$ (2,259)	$ -	$ 26,564	$ 45,019

Fair Value of Derivative Instruments
December 31, 2009

CSPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 168,137	$ 1,805	$ -	$ (135,599)	$ 34,343
Long-term Risk Management Assets	66,816	-	-	(42,934)	23,882
Total Assets	234,953	1,805	-	(178,533)	58,225
Current Risk Management Liabilities	156,463	2,574	-	(145,985)	13,052
Long-term Risk Management Liabilities	60,048	41	-	(49,776)	10,313
Total Liabilities	216,511	2,615	-	(195,761)	23,365
Total MTM Derivative Contract Net Assets (Liabilities)	$ 18,442	$ (810)	$ -	$ 17,228	$ 34,860

Fair Value of Derivative Instruments
March 31, 2010

I&M

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 274,350	$ 2,763	$ -	$ (230,409)	$ 46,704
Long-term Risk Management Assets	139,429	156	-	(90,931)	48,654
Total Assets	413,779	2,919	-	(321,340)	95,358
Current Risk Management Liabilities	258,206	4,672	-	(243,455)	19,423
Long-term Risk Management Liabilities	121,330	512	-	(104,536)	17,306
Total Liabilities	379,536	5,184	-	(347,991)	36,729
Total MTM Derivative Contract Net Assets (Liabilities)	$ 34,243	$ (2,265)	$ -	$ 26,651	$ 58,629

Fair Value of Derivative Instruments
December 31, 2009

I&M

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 167,847	$ 1,839	$ -	$ (135,248)	$ 34,438
Long-term Risk Management Assets	72,127	-	-	(42,993)	29,134

Total Assets	239,974	1,839	-	(178,241)	63,572
Current Risk Management Liabilities	156,561	2,596	-	(145,721)	13,436
Long-term Risk Management Liabilities	60,217	41	-	(49,872)	10,386
Total Liabilities	216,778	2,637	-	(195,593)	23,822
Total MTM Derivative Contract Net Assets (Liabilities)	$ 23,196	$ (798)	$ -	$ 17,352	$ 39,750

Fair Value of Derivative Instruments
March 31, 2010

OPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 377,428	$ 3,204	$ -	$ (321,405)	$ 59,227
Long-term Risk Management Assets	160,257	178	-	(116,689)	43,746
Total Assets	537,685	3,382	-	(438,094)	102,973
Current Risk Management Liabilities	360,508	5,332	-	(336,384)	29,456
Long-term Risk Management Liabilities	153,975	586	-	(134,208)	20,353
Total Liabilities	514,483	5,918	-	(470,592)	49,809
Total MTM Derivative Contract Net Assets (Liabilities)	$ 23,202	$ (2,536)	$ -	$ 32,498	$ 53,164

Fair Value of Derivative Instruments
December 31, 2009

OPCo

Risk Management Contracts	Hedging Contracts

Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 255,179	$ 2,199	$ -	$ (207,330)	$ 50,048
Long-term Risk Management Assets	88,064	-	-	(60,061)	28,003
Total Assets	343,243	2,199	-	(267,391)	78,051
Current Risk Management Liabilities	240,877	2,998	-	(219,484)	24,391
Long-term Risk Management Liabilities	81,186	47	-	(68,723)	12,510
Total Liabilities	322,063	3,045	-	(288,207)	36,901
Total MTM Derivative Contract Net Assets (Liabilities)	$ 21,180	$ (846)	$ -	$ 20,816	$ 41,150

Fair Value of Derivative Instruments
March 31, 2010

PSO

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 12,892	$ 170	$ -	$ (9,799)	$ 3,263
Long-term Risk Management Assets	2,279	1	-	(2,123)	157
Total Assets	15,171	171	-	(11,922)	3,420
Current Risk Management Liabilities	10,169	181	-	(9,814)	536
Long-term Risk Management Liabilities	2,567	7	-	(2,457)	117
Total Liabilities	12,736	188	-	(12,271)	653
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,435	$ (17)	$ -	$ 349	$ 2,767

Fair Value of Derivative Instruments
December 31, 2009

PSO

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 14,885	$ 179	$ -	$ (12,688)	$ 2,376
Long-term Risk Management Assets	2,640	-	-	(2,590)	50
Total Assets	17,525	179	-	(15,278)	2,426
Current Risk Management Liabilities	14,981	301	-	(12,703)	2,579
Long-term Risk Management Liabilities	2,913	-	-	(2,769)	144
Total Liabilities	17,894	301	-	(15,472)	2,723
Total MTM Derivative Contract Net Assets (Liabilities)	$ (369)	$ (122)	$ -	$ 194	$ (297)

Fair Value of Derivative Instruments
March 31, 2010

SWEPCo

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 17,797	$ 157	$ 17	$ (15,916)	$ 2,055
Long-term Risk Management Assets	3,747	1	3	(3,507)	244
Total Assets	21,544	158	20	(19,423)	2,299
Current Risk Management Liabilities	16,818	5	107	(15,941)	989
Long-term Risk Management Liabilities	4,680	6	-	(4,054)	632
Total Liabilities	21,498	11	107	(19,995)	1,621
	$ 46	$ 147	$ (87)	$ 572	$ 678

Total MTM Derivative Contract Net Assets (Liabilities)					

Fair Value of Derivative Instruments
December 31, 2009

SWEPCo

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 22,847	$ 169	$ 42	$ (20,009)	$ 3,049
Long-term Risk Management Assets	4,145	-	5	(4,066)	84
Total Assets	26,992	169	47	(24,075)	3,133
Current Risk Management Liabilities	20,788	-	89	(20,033)	844
Long-term Risk Management Liabilities	4,568	-	-	(4,347)	221
Total Liabilities	25,356	-	89	(24,380)	1,065
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,636	$ 169	$ (42)	$ 305	$ 2,068

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Balance Sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

The tables below present the Registrant Subsidiaries' activity of derivative risk management contracts for the three months ended March 31, 2010 and 2009:

Amount of Gain (Loss) Recognized
on Risk Management Contracts
For the Three Months Ended March 31, 2010

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution	$ 4,173	$ 9,607	$ 6,885	$ 10,221	$ 683	$ 788

Revenues						
Sales to AEP Affiliates	(2,361)	(1,562)	(1,443)	253	(176)	(308)
Regulatory Assets (a)	-	-	-	-	331	(47)
Regulatory Liabilities (a)	17,027	3,681	15,092	4,093	2,638	(1,011)
Total Gain (Loss) on Risk Management Contracts	$ 18,839	$ 11,726	$ 20,534	$ 14,567	$ 3,476	$ (578)

Amount of Gain (Loss) Recognized
on Risk Management Contracts
For the Three Months Ended March 31, 2009

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 9,817	$ 10,745	$ 18,178	$ 12,711	$ 1,255	$ 1,523
Sales to AEP Affiliates	(7,020)	(4,076)	(3,971)	(3,214)	(1,462)	(1,781)
Regulatory Assets (a)	(755)	-	-	-	-	(41)
Regulatory Liabilities (a)	20,622	2,237	5,562	2,697	334	386
Total Gain (Loss) on Risk Management Contracts	$ 22,664	$ 8,906	$ 19,769	$ 12,194	$ 127	$ 87

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current within the balance sheet.

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the Condensed Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the Condensed Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions (APCo, I&M, PSO, the non-Texas portion of SWEPCo generation and beginning in the second quarter of 2009 the Texas portion of SWEPCo generation) for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations." SWEPCo re-applied the accounting guidance for "Regulated Operations" for the generation portion of SWEPCo's Texas retail jurisdiction effective the second quarter of 2009.

Accounting for Fair Value Hedging Strategies

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

The Registrant Subsidiaries record realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on the Condensed Statements of Income. During the three months ended March 31, 2010 and 2009, the Registrant Subsidiaries did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal, heating oil and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the Condensed Statements of Income, or in Regulatory Assets or Regulatory Liabilities on the Condensed Balance Sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2010 and 2009, APCo, CSPCo, I&M and OPCo designated commodity derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Condensed Statements of Income. During the three months ended March 31, 2010 and 2009, the Registrant Subsidiaries designated cash flow hedging strategies of forecasted fuel purchases.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2010, APCo designated interest rate derivatives as cash flow hedges. During the three months ended March 31, 2009, OPCo designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Depreciation and Amortization expense on the Condensed Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2010 and 2009, SWEPCo designated foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on the Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2010

Commodity Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Balance in AOCI as of January 1, 2010	$(743)	$(376)	$(382)	$(366)	$(78)	$112
Changes in Fair Value Recognized in AOCI	(2,499)	(1,457)	(1,471)	(1,670)	86	3
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission and Distribution Revenues	26	65	54	76	-	-
Other Operation Expense	(6)	(8)	(6)	(5)	(6)	(7)
Maintenance Expense	(14)	(6)	(5)	(4)	(4)	(4)
Fuel and Other Consumables Used for Electric Generation	-	-	-	(9)	-	-
Purchased Electricity for Resale	146	382	316	440	-	-
Property, Plant and Equipment	(9)	(7)	(5)	(5)	(6)	(4)
Regulatory Assets (a)	648	-	81	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-	-
Balance in AOCI as of March 31, 2010	$(2,451)	$(1,407)	$(1,418)	$(1,543)	$(8)	$100

Interest Rate and Foreign Currency Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Balance in AOCI as of January 1, 2010	$ (6,450)	$ -	$ (9,514)	$ 12,172	$ (521)	$ (5,047)
Changes in Fair Value Recognized in AOCI	(456)	-	-	-	-	(107)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Depreciation and Amortization Expense	-	-	-	1	-	-
Interest Expense	418	-	252	(341)	46	207
	$ (6,488)	$ -	$ (9,262)	$ 11,832	$ (475)	$ (4,947)

Balance in AOCI as of March 31, 2010

Total Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Balance in AOCI as of January 1, 2010	$(7,193)	$(376)	$(9,896)	$11,806	$(599)	$(4,935)
Changes in Fair Value Recognized in AOCI	(2,955)	(1,457)	(1,471)	(1,670)	86	(104)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission and Distribution Revenues	26	65	54	76	-	-
Other Operation Expense	(6)	(8)	(6)	(5)	(6)	(7)
Maintenance Expense	(14)	(6)	(5)	(4)	(4)	(4)
Fuel and Other Consumables Used for Electric Generation	-	-	-	(9)	-	-
Purchased Electricity for Resale	146	382	316	440	-	-
Depreciation and Amortization Expense	-	-	-	1	-	-
Interest Expense	418	-	252	(341)	46	207
Property, Plant and Equipment	(9)	(7)	(5)	(5)	(6)	(4)
Regulatory Assets (a)	648	-	81	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-	-
Balance in AOCI as of March 31, 2010	$(8,939)	$(1,407)	$(10,680)	$10,289	$(483)	$(4,847)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current within the balance sheet.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2009

	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity Contracts						
Balance in AOCI as of January 1, 2009	$2,726	$1,531	$1,482	$1,898	$-	$-
Changes in Fair Value Recognized in AOCI	380	118	113	136	(24)	(21)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission and Distribution Revenues	(251)	(613)	(504)	(759)	-	-

Purchased Electricity for Resale	462	1,126	926	1,394	-	-
Regulatory Assets	1,639	-	163	-	-	-
Regulatory Liabilities	(890)	-	(89)	-	-	-
Balance in AOCI as of March 31, 2009	$4,066	$2,162	$2,091	$2,669	$(24)	$(21)

	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Interest Rate and Foreign Currency Contracts						
Balance in AOCI as of January 1, 2009	$(8,118)	$-	$(10,521)	$1,752	$(704)	$(5,924)
Changes in Fair Value Recognized in AOCI	-	-	-	263	-	(91)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Depreciation and Amortization Expense	-	-	(2)	1	-	-
Interest Expense	416	-	252	23	46	207
Balance in AOCI as of March 31, 2009	$(7,702)	$-	$(10,271)	$2,039	$(658)	$(5,808)

	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
TOTAL Contracts						
Balance in AOCI as of January 1, 2009	$(5,392)	$1,531	$(9,039)	$3,650	$(704)	$(5,924)
Changes in Fair Value Recognized in AOCI	380	118	113	399	(24)	(112)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission and Distribution Revenues	(251)	(613)	(504)	(759)	-	-
Purchased Electricity for Resale	462	1,126	926	1,394	-	-
Depreciation and Amortization Expense	-	-	(2)	1	-	-
Interest Expense	416	-	252	23	46	207
Regulatory Assets	1,639	-	163	-	-	-
Regulatory Liabilities	(890)	-	(89)	-	-	-
Balance in AOCI as of March 31, 2009	$(3,636)	$2,162	$(8,180)	$4,708	$(682)	$(5,829)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets at March 31, 2010 and December 31, 2009 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries'

Condensed Balance Sheets
March 31, 2010

Company	Hedging Assets (a) Commodity	Hedging Assets (a) Interest Rate and Foreign Currency	Hedging Liabilities (a) Commodity	Hedging Liabilities (a) Interest Rate and Foreign Currency	AOCI Gain (Loss) Net of Tax Commodity	AOCI Gain (Loss) Net of Tax Interest Rate and Foreign Currency
	(in thousands)					
APCo	$ 672	$ 207	$ (4,604)	$ (908)	$ (2,451)	$ (6,488)
CSPCo	345	-	(2,604)	-	(1,407)	-
I&M	362	-	(2,627)	-	(1,418)	(9,262)
OPCo	463	-	(2,999)	-	(1,543)	11,832
PSO	165	-	(182)	-	(8)	(475)
SWEPCo	151	3	(4)	(90)	100	(4,947)

Company	Expected to be Reclassified to Net Income During the Next Twelve Months Commodity	Expected to be Reclassified to Net Income During the Next Twelve Months Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$ (2,045)	$ (1,223)	21
CSPCo	(1,177)	-	21
I&M	(1,190)	(1,007)	21
OPCo	(1,278)	1,359	21
PSO	(5)	(87)	21
SWEPCo	102	(829)	32

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
December 31, 2009

Company	Hedging Assets (a) Commodity	Hedging Assets (a) Interest Rate and Foreign Currency	Hedging Liabilities (a) Commodity	Hedging Liabilities (a) Interest Rate and Foreign Currency	AOCI Gain (Loss) Net of Tax Commodity	AOCI Gain (Loss) Net of Tax Interest Rate and Foreign Currency
	(in thousands)					
APCo	$ 1,999	$ -	$ (3,542)	$ -	$ (743)	$ (6,450)
CSPCo	984	-	(1,794)	-	(376)	-
I&M	1,011	-	(1,809)	-	(382)	(9,514)
OPCo	1,242	-	(2,088)	-	(366)	12,172
PSO	178	-	(300)	-	(78)	(521)
SWEPCo	168	5	-	(46)	112	(5,047)

Expected to be Reclassified to
Net Income During the Next
Twelve Months

Company	Commodity	Interest Rate and Foreign Currency
	(in thousands)	
APCo	$ (691)	$ (1,301)
CSPCo	(349)	-
I&M	(358)	(1,007)
OPCo	(335)	1,359
PSO	(79)	(114)
SWEPCo	111	(829)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the Condensed Balance Sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

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

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), the Registrant Subsidiaries are obligated to post an amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. The following tables represent the Registrant Subsidiaries' aggregate fair value of such derivative contracts, the amount of collateral the Registrant Subsidiaries would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of March 31, 2010 and December 31, 2009:

	March 31, 2010		
Company	Aggregate Fair Value of Derivative Contracts	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
	(in thousands)		
APCo	$ 2,487	$ 7,362	$ 7,362
CSPCo	1,407	4,165	4,165
I&M	1,419	4,201	4,201
OPCo	1,619	4,793	4,793
PSO	652	3,072	2,420
SWEPCo	775	3,653	2,878

As of March 31, 2010, the Registrant Subsidiaries were not required to post any cash collateral.

	December 31, 2009		
Company	Aggregate Fair Value of Derivative Contracts	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
	(in thousands)		
APCo	$ 2,229	$ 8,433	$ 7,947
CSPCo	1,129	4,272	4,026
I&M	1,139	4,309	4,060
OPCo	1,315	4,975	4,688
PSO	689	2,772	2,083
SWEPCo	819	3,297	2,477

As of December 31, 2009, the Registrant Subsidiaries were not required to post any cash collateral.

In addition, a majority of the Registrant Subsidiaries' non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under borrowed debt in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management believes that a non-performance event under these provisions is unlikely. The following tables represent the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, the amount this exposure has been reduced by cash collateral posted by the Registrant Subsidiaries and if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of March 31, 2010 and December 31, 2009:

March 31, 2010

Company	Liabilities of Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
APCo	$ 210,308	$ 12,031	$ 51,454
CSPCo	118,468	6,806	28,714
I&M	119,474	6,864	28,959
OPCo	136,386	7,833	33,045
PSO	40	-	-
SWEPCo	158	-	86

December 31, 2009

Company	Liabilities of Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
APCo	$ 154,924	$ 3,115	$ 33,186
CSPCo	78,489	1,578	16,813
I&M	79,158	1,592	16,955
OPCo	91,430	1,838	19,615
PSO	40	-	40
SWEPCo	139	-	93

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

AEP utilizes its trustee’s external pricing service in its estimate of the fair value of the underlying investments held in the nuclear trusts. AEP’s investment managers review and validate the prices utilized by the trustee to determine fair value. AEP’s investment managers perform their own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee’s operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	United States Government	Corporate Debt	State and Local Government
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of March 31, 2010 and December 31, 2009 are summarized in the following table:

	March 31, 2010		December 31, 2009	
Company	Book Value	Fair Value	Book Value	Fair Value
		(in thousands)		
APCo	$ 3,411,244	$ 3,651,615	$ 3,477,306	$ 3,699,373
CSPCo	1,588,592	1,680,540	1,536,393	1,616,857
I&M	2,053,090	2,185,441	2,077,906	2,192,854
OPCo	3,329,109	3,495,805	3,242,505	3,380,084
PSO	968,808	1,020,923	968,121	1,007,183
SWEPCo	1,769,331	1,850,116	1,474,153	1,554,165

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.
- Target asset allocation is 50% fixed income and 50% equity securities.

I&M maintains trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

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

The following is a summary of nuclear trust fund investments at March 31, 2010 and December 31, 2009:

	March 31, 2010			December 31, 2009		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
			(in thousands)			
Cash and Cash Equivalents	$ 15,683	$ -	$ -	$ 14,412	$ -	$ -
Fixed Income Securities:						
United States Government	450,711	14,166	(1,890)	400,565	12,708	(3,472)
Corporate Debt	58,688	4,913	(2,115)	57,291	4,636	(2,177)
State and Local Government	326,354	3,402	509	368,930	7,924	991
Subtotal Fixed Income Securities	835,753	22,481	(3,496)	826,786	25,268	(4,658)
Equity Securities – Domestic	581,576	261,157	(118,469)	550,721	234,437	(119,379)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,433,012	$ 283,638	$ (121,965)	$ 1,391,919	$ 259,705	$ (124,037)

The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2010 and 2009:

Three Months Ended March 31,	Proceeds From Investment Sales	Purchases of Investments	Gross Realized Gains on Investment Sales	Gross Realized Losses on Investment Sales
		(in thousands)		
2010	$ 232,078	$ 247,632	$ 5,328	$ 181
2009	158,086	178,407	2,882	348

The adjusted cost of debt securities was $813 million and $801 million as of March 31, 2010 and December 31, 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at March 31, 2010 was as follows:

	Fair Value of Debt Securities (in thousands)
Within 1 year	$ 15,542
1 year – 5 years	308,892

5 years – 10 years		255,731
After 10 years		255,588
Total	$	835,753

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2010 and December 31, 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 3,734	$ 673,530	$ 28,138	$ (569,091)	$ 136,311
Cash Flow Hedges:					
Commodity Hedges (a)	-	5,137	-	(4,465)	672
Interest Rate/Foreign Currency Hedges (a)	-	207	-	-	207
Dedesignated Risk Management Contracts (b)	-	-	-	7,186	7,186
Total Risk Management Assets	$ 3,734	$ 678,874	$ 28,138	$ (566,370)	$ 144,376
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 3,832	$ 655,568	$ 9,451	$ (610,636)	$ 58,215
Cash Flow Hedges:					
Commodity Hedges (a)	-	9,069	-	(4,465)	4,604
Interest Rate/Foreign Currency Hedges (a)	-	908	-	-	908
DETM Assignment (c)	-	-	-	1,822	1,822
Total Risk Management Liabilities	$ 3,832	$ 665,545	$ 9,451	$ (613,279)	$ 65,549

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 421	$ -	$ -	$ 51	$ 472
Risk Management Assets					
Risk Management Contracts (a)	2,344	449,406	12,866	(360,248)	104,368

Cash Flow and Fair Value Hedges (a)		-		3,620		-		(1,621)		1,999
Dedesignated Risk Management Contracts (b)		-		-		-		8,730		8,730
Total Risk Management Assets		2,344		453,026		12,866		(353,139)		115,097
Total Assets	$	2,765	$	453,026	$	12,866	$	(353,088)	$	115,569
Liabilities:										
Risk Management Liabilities										
Risk Management Contracts (a)	$	2,648	$	422,063	$	3,438	$	(388,265)	$	39,884
Cash Flow and Fair Value Hedges (a)		-		5,163		-		(1,621)		3,542
DETM Assignment (c)		-		-		-		2,730		2,730
Total Risk Management Liabilities	$	2,648	$	427,226	$	3,438	$	(387,156)	$	46,156

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

CSPCo

		Level 1		Level 2		Level 3		Other		Total
Assets:						(in thousands)				
Risk Management Assets										
Risk Management Commodity Contracts (a) (g)	$	2,113	$	382,034	$	15,918	$	(322,850)	$	77,215
Cash Flow Hedges:										
Commodity Hedges (a)		-		2,870		-		(2,525)		345
Dedesignated Risk Management Contracts (b)		-		-		-		4,066		4,066
Total Risk Management Assets	$	2,113	$	384,904	$	15,918	$	(321,309)	$	81,626
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (a) (g)	$	2,168	$	371,835	$	5,348	$	(346,379)	$	32,972
Cash Flow Hedges:										
Commodity Hedges (a)		-		5,129		-		(2,525)		2,604
DETM Assignment (c)		-		-		-		1,031		1,031
Total Risk Management Liabilities	$	2,168	$	376,964	$	5,348	$	(347,873)	$	36,607

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

CSPCo

		Level 1		Level 2		Level 3		Other		Total
Assets:						(in thousands)				
Other Cash Deposits (d)	$	16,129	$	-	$	-	$	21	$	16,150
Risk Management Assets										
Risk Management Contracts (a)		1,188		227,150		6,518		(182,038)		52,818
Cash Flow and Fair Value Hedges (a)		-		1,805		-		(821)		984
Dedesignated Risk Management Contracts (b)		-		-		-		4,423		4,423

Total Risk Management Assets	1,188	228,955	6,518	(178,436)	58,225
Total Assets	$ 17,317	$ 228,955	$ 6,518	$ (178,415)	$ 74,375
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 1,342	$ 213,330	$ 1,742	$ (196,226)	$ 20,188
Cash Flow and Fair Value Hedges (a)	-	2,615	-	(821)	1,794
DETM Assignment (c)	-	-	-	1,383	1,383
Total Risk Management Liabilities	$ 1,342	$ 215,945	$ 1,742	$ (195,664)	$ 23,365

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 2,131	$ 393,603	$ 16,054	$ (320,892)	$ 90,896
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,908	-	(2,546)	362
Dedesignated Risk Management Contracts (b)	-	-	-	4,100	4,100
Total Risk Management Assets	2,131	396,511	16,054	(319,338)	95,358
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	6,057	-	9,626	15,683
Fixed Income Securities:					
United States Government	-	450,711	-	-	450,711
Corporate Debt	-	58,688	-	-	58,688
State and Local Government	-	326,354	-	-	326,354
Subtotal Fixed Income Securities	-	835,753	-	-	835,753
Equity Securities – Domestic (f)	581,576	-	-	-	581,576
Total Spent Nuclear Fuel and Decommissioning Trusts	581,576	841,810	-	9,626	1,433,012
Total Assets	$ 583,707	$ 1,238,321	$ 16,054	$ (309,712)	$ 1,528,370
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 2,186	$ 369,967	$ 5,392	$ (344,483)	$ 33,062
Cash Flow Hedges:					
Commodity Hedges (a)	-	5,173	-	(2,546)	2,627
DETM Assignment (c)	-	-	-	1,040	1,040
Total Risk Management Liabilities	$ 2,186	$ 375,140	$ 5,392	$ (345,989)	$ 36,729

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 1,198	$ 231,777	$ 6,571	$ (181,446)	$ 58,100
Cash Flow and Fair Value Hedges (a)	-	1,839	-	(828)	1,011
Dedesignated Risk Management Contracts (b)	-	-	-	4,461	4,461
Total Risk Management Assets	1,198	233,616	6,571	(177,813)	63,572
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	3,562	-	10,850	14,412
Fixed Income Securities:					
United States Government	-	400,565	-	-	400,565
Corporate Debt	-	57,291	-	-	57,291
State and Local Government	-	368,930	-	-	368,930
Subtotal Fixed Income Securities	-	826,786	-	-	826,786
Equity Securities (f)	550,721	-	-	-	550,721
Total Spent Nuclear Fuel and Decommissioning Trusts	550,721	830,348	-	10,850	1,391,919
Total Assets	$ 551,919	$ 1,063,964	$ 6,571	$ (166,963)	$ 1,455,491
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 1,353	$ 213,242	$ 1,755	$ (195,732)	$ 20,618
Cash Flow and Fair Value Hedges (a)	-	2,637	-	(828)	1,809
DETM Assignment (c)	-	-	-	1,395	1,395
Total Risk Management Liabilities	$ 1,353	$ 215,879	$ 1,755	$ (195,165)	$ 23,822

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 2,054	$ -	$ -	$ 1,229	$ 3,283
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	2,432	512,728	18,344	(435,673)	97,831
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,370	-	(2,907)	463
Dedesignated Risk Management Contracts (b)	-	-	-	4,679	4,679
Total Risk Management Assets	2,432	516,098	18,344	(433,901)	102,973
Total Assets	$ 4,486	$ 516,098	$ 18,344	$(432,672)	$106,256

Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 2,495	$ 501,643	$ 6,164	$(464,678)	$ 45,624
Cash Flow Hedges:					
Commodity Hedges (a)	-	5,906	-	(2,907)	2,999
DETM Assignment (c)	-	-	-	1,186	1,186
Total Risk Management Liabilities	$ 2,495	$ 507,549	$ 6,164	$(466,399)	$ 49,809

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 1,075	$ -	$ -	$ 24	$ 1,099
Risk Management Assets					
Risk Management Contracts (a)	1,383	332,904	7,644	(270,272)	71,659
Cash Flow and Fair Value Hedges (a)	-	2,199	-	(957)	1,242
Dedesignated Risk Management Contracts (b)	-	-	-	5,150	5,150
Total Risk Management Assets	1,383	335,103	7,644	(266,079)	78,051
Total Assets	$ 2,458	$ 335,103	$ 7,644	$ (266,055)	$ 79,150
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 1,562	$ 317,114	$ 2,075	$ (287,549)	$ 33,202
Cash Flow and Fair Value Hedges (a)	-	3,045	-	(957)	2,088
DETM Assignment (c)	-	-	-	1,611	1,611
Total Risk Management Liabilities	$ 1,562	$ 320,159	$ 2,075	$ (286,895)	$ 36,901

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ -	$ 14,983	$ 4	$ (11,732)	$ 3,255
Cash Flow Hedges:					
Commodity Hedges (a)	-	170	-	(5)	165
Total Risk Management Assets	$ -	$ 15,153	$ 4	$ (11,737)	$ 3,420
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ -	$ 12,550	$ 2	$ (12,081)	$ 471
Cash Flow Hedges:					

Commodity Hedges (a)		-		187		-		(5)		182
Total Risk Management Liabilities	$	-	$	12,737	$	2	$	(12,086)	$	653

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

PSO

		Level 1		Level 2		Level 3		Other		Total
Assets:						(in thousands)				
Risk Management Assets										
Risk Management Contracts (a)	$	-	$	17,494	$	14	$	(15,260)	$	2,248
Cash Flow and Fair Value Hedges (a)		-		179		-		(1)		178
Total Risk Management Assets	$	-	$	17,673	$	14	$	(15,261)	$	2,426
Liabilities:										
Risk Management Liabilities										
Risk Management Contracts (a)	$	-	$	17,865	$	12	$	(15,454)	$	2,423
Cash Flow and Fair Value Hedges (a)		-		301		-		(1)		300
Total Risk Management Liabilities	$	-	$	18,166	$	12	$	(15,455)	$	2,723

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2010

SWEPCo

		Level 1		Level 2		Level 3		Other		Total
Assets:						(in thousands)				
Risk Management Assets										
Risk Management Commodity Contracts (a) (g)	$	-	$	21,234	$	7	$	(19,096)	$	2,145
Cash Flow Hedges:										
Commodity Hedges (a)		-		157		-		(6)		151
Interest Rate/Foreign Currency Hedges (a)		-		19		-		(16)		3
Total Risk Management Assets	$	-	$	21,410	$	7	$	(19,118)	$	2,299
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (a) (g)	$	-	$	21,192	$	3	$	(19,668)	$	1,527
Cash Flow Hedges:										
Commodity Hedges (a)		-		10		-		(6)		4
Interest Rate/Foreign Currency Hedges (a)		-		106		-		(16)		90
Total Risk Management Liabilities	$	-	$	21,308	$	3	$	(19,690)	$	1,621

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

SWEPCo

		Level 1		Level 2		Level 3		Other		Total
Assets:						(in thousands)				
Risk Management Assets										
Risk Management Contracts (a)	$	-	$	26,945	$	22	$	(24,007)	$	2,960

Cash Flow and Fair Value Hedges (a)		-		216		-		(43)		173
Total Risk Management Assets	$	-	$	27,161	$	22	$	(24,050)	$	3,133
Liabilities:										
Risk Management Liabilities										
Risk Management Contracts (a)	$	-	$	25,312	$	19	$	(24,312)	$	1,019
Cash Flow and Fair Value Hedges (a)		-		89		-		(43)		46
Total Risk Management Liabilities	$	-	$	25,401	$	19	$	(24,355)	$	1,065

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(c) See "Natural Gas Contracts with DETM" section of Note 15 in the 2009 Annual Report.
(d) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(f) Amounts represent publicly traded equity securities and equity-based mutual funds.
(g) Substantially comprised of power contracts for APCo, CSPCo, I&M and OPCo and coal contracts for PSO and SWEPCo.

There have been no transfers between Level 1 and Level 2 during the three months ended March 31, 2010.

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

Three Months Ended March 31, 2010		APCo		CSPCo		I&M		OPCo		PSO		SWEPCo
						(in thousands)						
Balance as of January 1, 2010	$	9,428	$	4,776	$	4,816	$	5,569	$	2	$	3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		8,947		5,056		5,099		5,818		-		-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-		6,122		-		6,987		-		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-		-		-		-		-		-
Purchases, Issuances and Settlements (c)		(10,221)		(5,743)		(5,792)		(6,612)		-		-
Transfers into Level 3 (d) (h)		439		222		224		259		-		-
Transfers out of Level 3 (e) (h)		269		137		138		159		-		-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		9,825		-		6,177		-		-		1

Balance as of March 31, 2010	$ 18,687	$ 10,570	$ 10,662	$ 12,180	$ 2	$ 4

Three Months Ended March 31, 2009	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of January 1, 2009	$ 8,009	$ 4,497	$ 4,352	$ 5,563	$ (2)	$ (3)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(3,898)	(2,189)	(2,118)	(2,700)	3	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	3,264	-	4,045	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (f)	(74)	(42)	(40)	(52)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7,810	764	3,898	946	-	-
Balance as of March 31, 2009	$ 11,847	$ 6,294	$ 6,092	$ 7,802	$ 1	$ 2

(a) Included in revenues on the Condensed Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
(h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

10. INCOME TAXES

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2001. The Registrant Subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that the ultimate resolution of these audits will not materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Legislation – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

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 by the Registrant Subsidiaries in March 2010. This reduction did not materially affect the Registrant Subsidiaries' cash flows or financial condition. For the three months ended March 31, 2010, the Registrant Subsidiaries reflected a decrease in deferred tax assets, which was partially offset by recording net tax regulatory assets in jurisdictions with regulated operations, resulting in a decrease in net income as follows:

Company	Net Reduction to Deferred Tax Assets	Tax Regulatory Assets, Net	Decrease in Net Income
	(in thousands)		
APCo	$ 9,397	$ 8,831	$ 566
CSPCo	4,386	2,970	1,416
I&M	7,212	6,528	684
OPCo	8,385	4,020	4,365
PSO	3,172	3,172	-
SWEPCo	3,412	3,412	-

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2010 were:

Company	Type of Debt	Principal Amount (in thousands)	Interest Rate (%)	Due Date

Issuances:

APCo	Pollution Control Bonds	$	17,500	4.625	2021
CSPCo	Floating Rate Notes		150,000	Variable	2012
OPCo	Pollution Control Bonds		86,000	3.125	2043
SWEPCo	Senior Unsecured Notes		350,000	6.20	2040
SWEPCo	Pollution Control Bonds		53,500	3.25	2015

Company	Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
APCo	Land Note	$	4	13.718	2026
APCo	Notes Payable – Affiliated		100,000	4.708	2010
CSPCo	Notes Payable – Affiliated		100,000	4.64	2010
I&M	Notes Payable – Affiliated		25,000	5.375	2010
SWEPCo	Notes Payable – Affiliated		50,000	4.45	2010
SWEPCo	Pollution Control Bonds		53,500	Variable	2019

On behalf of OPCo, trustees held $303 million of reacquired auction-rate tax-exempt long-term debt as of March 31, 2010.

In April 2010, OPCo retired $400 million of variable rate Senior Unsecured Notes due in 2010 and I&M issued $85 million of 4.00% Notes Payable due in 2014.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to the Parent provided funds are legally available. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to the Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant Subsidiaries from participating “in the making or paying of any dividends of such public utility from any funds properly included in capital account.” The term “capital account” is not defined in the Federal Power Act or its regulations. As applicable, the Registrant Subsidiaries understand “capital account” to mean the par value of the common stock multiplied by the number of shares outstanding.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of their respective ownership of such plants, this reserve applies to APCo and I&M.

None of these restrictions limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Charter and Leverage Restrictions

Provisions within the articles or certificates of incorporation of the Registrant Subsidiaries relating to preferred stock or shares restrict the payment of cash dividends on common and preferred stock or shares. Pursuant to credit agreement leverage restrictions, as of March 31, 2010, approximately $180 million of the retained earnings of APCo, $149 million of the retained earnings of CSPCo, $5 million of the retained earnings of I&M, $243 million of the retained earnings of OPCo, $102 million of the retained earnings of SWEPCo and none of the retained earnings of PSO have restrictions related to the payment of dividends.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of March 31, 2010 and December 31, 2009 is included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the three months ended March 31, 2010 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of March 31, 2010	Authorized Short-Term Borrowing Limit
			(in thousands)			
APCo	$ 379,016	$ -	$ 246,229	$ -	$ (347,425)	$ 600,000
CSPCo	134,592	37,818	32,368	14,303	37,818	350,000
I&M	-	151,044	-	101,121	85,186	500,000
OPCo	-	618,559	-	470,254	617,299	600,000
PSO	72,418	74,751	26,958	51,041	(68,743)	300,000
SWEPCo	78,616	274,958	39,458	168,501	238,817	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Three Months Ended March 31, 2010	2009
Maximum Interest Rate	0.34%	2.28%
Minimum Interest Rate	0.09%	1.22%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2010 and 2009 are summarized for all Registrant Subsidiaries in the following table:

Average Interest Rate for Funds Borrowed from	Average Interest Rate for Funds Loaned to

	the Utility Money Pool for the Three Months Ended March 31,		the Utility Money Pool for the Three Months Ended March 31,	
	2010	2009	2010	2009
Company				
APCo	0.16%	1.76%	-%	-%
CSPCo	0.18%	1.62%	0.14%	-%
I&M	-%	1.86%	0.16%	1.76%
OPCo	-%	1.65%	0.16%	-%
PSO	0.16%	2.01%	0.16%	1.63%
SWEPCo	0.19%	1.86%	0.13%	1.68%

To meet its short-term borrowing needs, DHLC is also a member of the Utility Money Pool. Effective January 1, 2010, SWEPCo no longer consolidates DHLC. DHLC's money pool activity for the three months ended March 31, 2010 is described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of March 31, 2010
		(in thousands)		
$ 17,886	$ -	$ 13,195	$ -	$ 13,060

DHLC's maximum, minimum and average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2010 were as follows:

Three Months Ended March 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2010	0.34%	0.09%	-%	-%	0.16%	-%

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		March 31, 2010		December 31, 2009	
Company	Type of Debt	Outstanding Amount (in thousands)	Interest Rate (b)	Outstanding Amount (in thousands)	Interest Rate (b)
SWEPCo	Line of Credit – Sabine (a)	$ 13,218	2.12%	$ 6,890	2.06%

(a) Sabine Mining Company is a consolidated variable interest entity.
(b) Weighted average rate.

Credit Facilities

AEP has credit facilities totaling $3 billion to support the commercial paper program. The facilities are structured as two $1.5 billion credit facilities, of which $750 million may be issued under each credit facility as letters of credit. As of March 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $300 thousand for I&M and $4 million for SWEPCo.

The Registrant Subsidiaries and certain other companies in the AEP System have a $627 million 3-year credit agreement. Under the facility, letters of credit may be issued. As of March 31, 2010, $477 million of letters of credit were issued to support variable rate Pollution Control Bonds as follows:

Company	Amount (in thousands)
APCo	$ 232,292
I&M	77,886
OPCo	166,899

Sale of Receivables – AEP Credit

Under a securitization arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the participant's income statement. AEP Credit purchases accounts receivable through purchase agreements with CSPCo, I&M, OPCo, PSO, SWEPCo and a portion of APCo. APCo does not have regulatory authority to sell its West Virginia accounts receivable. Customer accounts receivable securitized for the electric operating companies are managed by the Registrant Subsidiaries. The Registrant Subsidiaries continue to service the receivables.

The amount of securitized accounts receivable and accrued unbilled revenues for each Registrant Subsidiary was as follows:

Company	March 31, 2010	December 31, 2009
	(in thousands)	
APCo	$ 184,319	$ 143,938
CSPCo	172,014	169,095
I&M	131,480	130,193
OPCo	168,388	160,977
PSO	71,675	73,518
SWEPCo	107,259	117,297

The fees paid by the Registrant Subsidiaries to AEP Credit for factoring customer accounts receivable were:

Company	Three Months Ended March 31, 2010

	(in thousands)
APCo	$ 1,881
CSPCo	2,908
I&M	1,787
OPCo	2,700
PSO	1,384
SWEPCo	1,671

The Registrant Subsidiaries proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2010 were:

Company	Three Months Ended March 31, 2010 (in thousands)
APCo	$ 441,711
CSPCo	424,685
I&M	339,208
OPCo	441,510
PSO	214,647
SWEPCo	318,959

12. COMPANY-WIDE STAFFING AND BUDGET REVIEW

In April 2010, management 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 seeking 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.

Management expects to record a charge to expense in the second quarter of 2010 related to these initiatives. At this time, management is unable to predict the impact of these initiatives on net income, cash flows and financial condition.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

EXECUTIVE OVERVIEW

Economic Conditions

The Registrant Subsidiaries' retail margins increased primarily due to rate increases in Indiana, Ohio, Oklahoma and Virginia and higher residential demand for electricity as a result of favorable weather. Margins from off-system sales increased for all Registrant Subsidiaries. The largest increases were in the eastern region primarily due to higher physical sales reflecting favorable generation availability.

During 2009, the Registrant Subsidiaries' operations were impacted by difficult economic conditions especially their industrial sales. In 2010, APCo, CSPCo and OPCo saw declines in their industrial sales reflecting curtailments or closures of facilities. In 2009, CSPCo's and OPCo's largest customer, Ormet, a major industrial customer, currently operating at a reduced load of approximately 330 MW, (Ormet operated at an approximate 500 MW load in 2008), announced that it will continue operations at this reduced level. In February 2009, Century Aluminum, a major industrial customer (325 MW load) of APCo, announced the curtailment of operations at its Ravenswood, WV facility. In 2010, I&M's, PSO's and SWEPCo's industrial usage increased.

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 by the Registrant Subsidiaries in March 2010. This reduction did not materially affect the Registrant Subsidiaries' cash flows or financial condition. For the three months ended March 31, 2010, the Registrant Subsidiaries reflected a decrease in deferred tax assets, which was partially offset by recording net tax regulatory assets in jurisdictions with regulated operations, resulting in a decrease in net income as follows:

Company	Net Reduction to Deferred Tax Assets	Tax Regulatory Assets, Net	Decrease in Net Income
		(in thousands)	
APCo	$ 9,397	$ 8,831	$ 566
CSPCo	4,386	2,970	1,416
I&M	7,212	6,528	684
OPCo	8,385	4,020	4,365
PSO	3,172	3,172	-
SWEPCo	3,412	3,412	-

FINANCIAL CONDITION

LIQUIDITY

Sources of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities through the Utility Money Pool. AEP and its Registrant Subsidiaries operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity. Under each credit facility, $750 million may be issued as letters of credit (LOC). The Registrant Subsidiaries generally use short-term funding sources (the Utility Money Pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leasebacks, leasing arrangements and additional capital contributions from Parent.

Management believes that the Registrant Subsidiaries have adequate liquidity, through the Utility Money Pool and projected cash flows from their operations, to support planned business operations and capital expenditures. Long-term debt of $200 million, $150 million and $680 million will mature in 2010 for APCo, CSPCo and OPCo, respectively. In 2009, OPCo issued $500 million of senior notes which were used in April 2010 to pay $400 million of senior unsecured notes at maturity.

The Registrant Subsidiaries and certain other companies in the AEP System entered into a $627 million 3-year credit agreement. The Registrant Subsidiaries may issue LOCs under the credit facility. Each subsidiary has a borrowing/LOC limit under the credit facility. As of March 31, 2010, a total of $477 million of LOCs were issued under the credit agreement to support variable rate demand notes. The following table shows each Registrant Subsidiaries' borrowing/LOC limit under the credit facility and the outstanding amount of LOCs.

Company	Credit Facility Borrowing/LOC Limit	LOC Amount Outstanding Against $627 million Agreement at March 31, 2010
	(in millions)	
APCo	$ 300	$ 232
CSPCo	230	-
I&M	230	78
OPCo	400	167
PSO	65	-
SWEPCo	230	-

Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital.

SIGNIFICANT FACTORS

Company-wide Staffing and Budget Review

In April 2010, management 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.

Management expects to record a charge to expense in the second quarter of 2010 related to these initiatives. At this time, management is unable to predict the impact of these initiatives on net income, cash flows and financial condition.

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries 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.

The Registrant Subsidiaries 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 I&M's nuclear units. Management is also engaged in 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 Issues" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" 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 the Registrant Subsidiaries install additional controls on their generating plants to limit CO2 emissions and receive regulatory approvals to increase rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by the Registrant 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. Management would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect the Registrant Subsidiaries adversely because the regulators could limit the amount or timing of increased costs that would be recoverable through higher rates. In addition, to the extent the Registrant Subsidiaries' costs are relatively higher than their competitors' costs, such as operators of nuclear generation, it could reduce off-system sales or cause the Registrant Subsidiaries 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 the Registrant Subsidiaries have generating facilities. Certain states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). The Registrant Subsidiaries 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. The Registrant Subsidiaries have been named in pending lawsuits, which management is vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on 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 the Registrant 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 net income, cash flows and financial condition.

For detailed information on global warming and the actions the AEP System is taking 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 "Combined Management Discussion and Analysis of Registrant Subsidiaries."

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncement Adopted During the First Quarter of 2010

The Registrant Subsidiaries prospectively adopted ASU 2009-17 "Consolidation" effective January 1, 2010. SWEPCo no longer consolidates 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, management cannot determine the impact on the reporting of the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

The Registrant Subsidiaries' risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. Also, see Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to the Registrant

Subsidiaries' risk management contracts.

The following tables summarize 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 thousands)

APCo

Total MTM Risk Management Contract Net Assets at December 31, 2009	$45,197
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(7,755)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(35)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	(61)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	6,391
Total MTM Risk Management Contract Net Assets	43,737
Cash Flow Hedge Contracts	(4,633)
DETM Assignment (e)	(1,822)
Collateral Deposits	41,545
Total MTM Derivative Contract Net Assets at March 31, 2010	$78,827

OPCo

Total MTM Risk Management Contract Net Assets at December 31, 2009	$26,330
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(5,753)
Fair Value of New Contracts at Inception When Entered During the Period (a)	3,028
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	(715)
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(100)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	5,063
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	28
Total MTM Risk Management Contract Net Assets	27,881
Cash Flow Hedge Contracts	(2,536)
DETM Assignment (e)	(1,186)
Collateral Deposits	29,005
Total MTM Derivative Contract Net Assets at March 31, 2010	$53,164

PSO

Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$(369)
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(185)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(10)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	2
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	2,997
Total MTM Risk Management Contract Net Assets	2,435
Cash Flow Hedge Contracts	(17)
Collateral Deposits	349
Total MTM Derivative Contract Net Assets at March 31, 2010	$2,767

SWEPCo

Total MTM Risk Management Contract Net Assets at December 31, 2009	$1,636
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(926)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(16)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	2
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(650)
Total MTM Risk Management Contract Net Assets	46
Cash Flow Hedge Contracts	60
Collateral Deposits	572
Total MTM Derivative Contract Net Assets at March 31, 2010	$678

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) 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 Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.
(e) See "Natural Gas Contracts with DETM" section of Note 15 of the 2009 Annual Report.

The following tables present the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate or (require) cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
March 31, 2010
(in thousands)

APCo	Remainder 2010	2011-2013	2014	Total
Level 1 (a)	$ (99)	$ 1	$ -	$ (98)
Level 2 (b)	10,109	7,553	300	17,962
Level 3 (c)	8,887	7,793	2,007	18,687
Total	18,897	15,347	2,307	36,551
Dedesignated Risk Management Contracts (d)	3,711	3,475	-	7,186
Total MTM Risk Management Contract Net Assets	$ 22,608	$ 18,822	$ 2,307	$ 43,737

OPCo	Remainder 2010	2011-2013	2014	Total
Level 1 (a)	$ (64)	$ 1	$ -	$ (63)
Level 2 (b)	7,412	3,478	195	11,085
Level 3 (c)	5,799	5,074	1,307	12,180
Total	13,147	8,553	1,502	23,202
	2,416	2,263	-	4,679

Dedesignated Risk Management Contracts (d)				
Total MTM Risk Management Contract Net Assets	$ 15,563	$ 10,816	$ 1,502	$ 27,881

PSO	Remainder 2010	2011 - 2013	Total
Level 1 (a)	$ -	$ -	$ -
Level 2 (b)	2,708	(275)	2,433
Level 3 (c)	2	-	2
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 2,710	$ (275)	$ 2,435

SWEPCo	Remainder 2010	2011-2013	Total
Level 1 (a)	$ -	$ -	$ -
Level 2 (b)	1,235	(1,193)	42
Level 3 (c)	4	-	4
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 1,239	$ (1,193)	$ 46

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

Credit Risk

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at March 31, 2010, a near term typical change in commodity prices is not expected to have a material effect on net income, cash flows or financial condition.

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

	March 31, 2010 (in thousands)				December 31, 2009 (in thousands)			
Company	End	High	Average	Low	End	High	Average	Low
APCo	$ 209	$ 659	$ 306	$ 141	$ 275	$ 699	$ 333	$ 151
OPCo	162	545	256	117	201	530	244	113
PSO	9	70	19	5	10	34	12	4
SWEPCo	13	93	27	8	16	49	18	6

Management back-tests its 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 the VaR calculations capture recent price movements, management also performs regular stress testing of the portfolio to understand the exposure to extreme price movements. Management employs 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. Management then researches the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the Commercial Operations Risk Committee as appropriate.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which 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 the Registrant Subsidiaries' outstanding debt as of March 31, 2010 and December 31, 2009, the estimated EaR on the Registrant Subsidiaries' debt portfolio was as follows:

Company	March 31, 2010	December 31, 2009
	(in thousands)	
APCo	$ 1,295	$ 1,837
CSPCo	337	216
I&M	267	227
OPCo	1,297	1,373
PSO	85	119
SWEPCo	80	305

CONTROLS AND PROCEDURES

During the first quarter of 2010, management, including the principal executive officer and principal financial officer of each of AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of March 31, 2010, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of 2010 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 4 incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2009 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2009 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Turk Plant permits could be reversed on appeal. (Applies to AEP and SWEPCo)

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN). The Arkansas Court of Appeals issued a unanimous decision that may reverse the APSC’s grant of the CECPN. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals’ decision.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality (ADEQ). In January 2010, 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 of the APCEC’s decision 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. If SWEPCo is unable to complete the Turk Plant construction and place it in service or if SWEPCo cannot recover all of the investment in and the expenses of the Turk Plant, it would reduce future net income and cash flows and impact financial condition unless the resultant losses can be fully recovered, with a return on any unrecovered balances, through rates in all of its jurisdictions.

Oklahoma may require us to refund fuel costs that we have collected. (Applies to PSO.)

In July 2009, the OCC initiated a proceeding to review PSO’s fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudency review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder’s portion of off-system sales margins sharing decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

Rate recovery approved in Oklahoma may be overturned on appeal. (Applies to AEP and PSO)

In January 2009, the OCC issued a final order approving an $81 million increase in PSO’s non-fuel base revenues based on a 10.5% return on equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. If the intervenors' appeals are successful, it could reduce future net income and cash flows and impact financial condition.

Risks Related to Owning and Operating Generation Assets and Selling Power

We may not fully recover the costs of repairing or replacing damaged equipment in Cook Plant Unit 1 and may be required to pay additional accidental outage insurance proceeds to ratepayers. (Applies to AEP and I&M)

Cook Plant Unit 1 is a 1,084 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations, which resulted in a small fire on the electric generator. Unit 1 resumed operations in December 2009 at reduced power, but repair of the property damage and replacement of the turbine rotors and other equipment are estimated to cost approximately $395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process.

In March 2009, the IURC approved a settlement agreement with intervenors to collect a prior under-recovered fuel balance. Under the settlement agreement, a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. Separately, in March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment related to the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP or its publicly-traded subsidiaries during the quarter ended March 31, 2010 of equity securities that are registered by AEP or its publicly-traded subsidiaries pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
01/01/10 – 01/31/10	-	$ -	-	$ -
02/01/10 – 02/28/10	-	-	-	-
03/01/10 – 03/31/10	55(a)	69.86	-	-

(a) APCo purchased 50 shares of its 4.50% cumulative preferred stock and OPCo purchased 5 shares of its 4.50% cumulative preferred stock in privately-negotiated transactions outside of an announced program.

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo, OPCo, PSO and SWEPCo

10 – Amended and Restated AEP System Long-term Incentive Plan.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: April 30, 2010