Appendix A to the
Proxy Statement

American Electric Power

2010 Annual Report

Audited Consolidated Financial Statements and Management's Financial Discussion and Analysis

AMERICAN ELECTRIC POWER

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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 Foundation	AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate.
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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
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	Cleco Corporation, a nonaffiliated utility company.
CO_2	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.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
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.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.

Term	Meaning
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in North America outside of ERCOT.
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.
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.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
NEIL	Nuclear Electric Insurance Limited.
NO_x	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.

Term	Meaning
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.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System’s Utility Money Pool.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in “Item 7 – Management’s Financial Discussion and Analysis,” but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “could,” “would,” “project,” “continue” and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document speak only as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- 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 resolve I&M’s Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation.
- 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, captive insurance entity 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, cyber security threats and other catastrophic events.
- Our ability to recover through rates or prices any remaining unrecovered investment 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.

AEP COMMON STOCK AND DIVIDEND INFORMATION

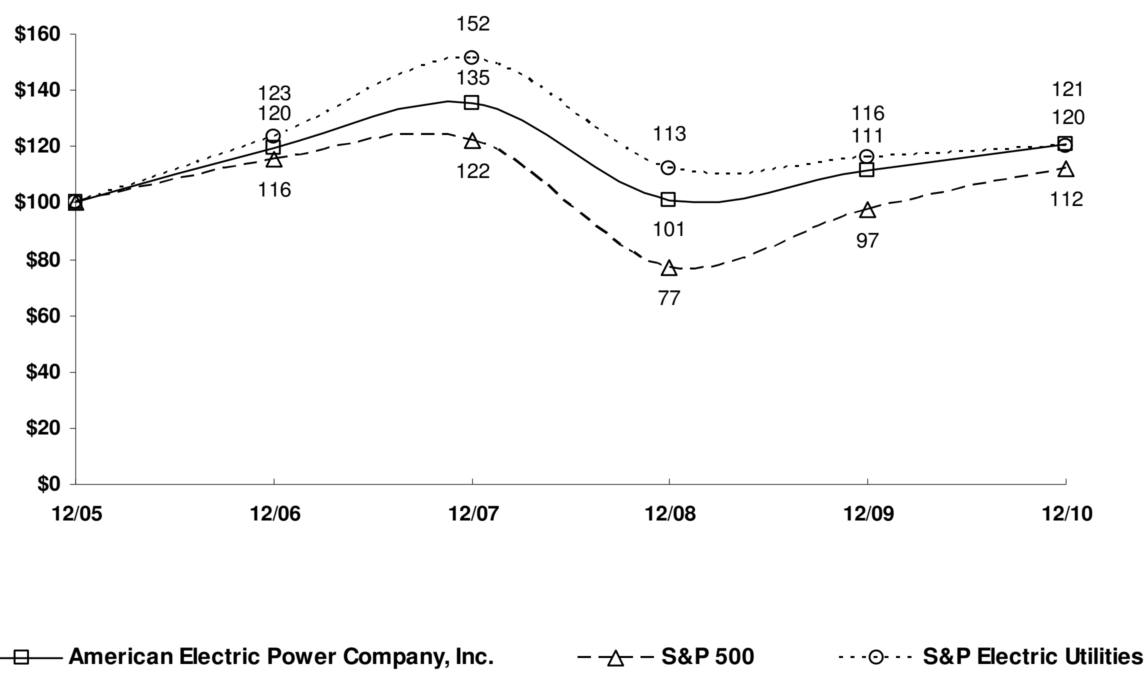
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended		High		Low		Quarter-End Closing Price		Dividend
December 31, 2010	$	37.94	$	34.92	$	35.98	$	0.46
September 30, 2010		36.93		31.87		36.23		0.42
June 30, 2010		35.00		28.17		32.30		0.42
March 31, 2010		36.86		32.68		34.18		0.41
December 31, 2009	$	36.51	$	29.59	$	34.79	$	0.41
September 30, 2009		32.36		28.07		30.99		0.41
June 30, 2009		29.16		24.75		28.89		0.41
March 31, 2009		34.34		24.00		25.26		0.41

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2010, AEP had approximately 91,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index
and the S&P Electric Utilities Index



*$100 invested on 12/31/05 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2010	2009	2008	2007	2006
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,427	$ 13,489	$ 14,440	$ 13,380	$ 12,622
Operating Income	$ 2,663	$ 2,771	$ 2,787	$ 2,319	$ 1,966
Income Before Discontinued Operations and Extraordinary Loss	$ 1,218	$ 1,370	$ 1,376	$ 1,153	$ 1,001
Discontinued Operations, Net of Tax	-	-	12	24	10
Income Before Extraordinary Loss	1,218	1,370	1,388	1,177	1,011
Extraordinary Loss, Net of Tax	-	(5)	-	(79)	-
Net Income	1,218	1,365	1,388	1,098	1,011
Less: Net Income Attributable to Noncontrolling Interests	4	5	5	6	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,214	1,360	1,383	1,092	1,005
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,211	$ 1,357	$ 1,380	$ 1,089	$ 1,002
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 53,740	$ 51,684	$ 49,710	$ 46,145	$ 42,021
Accumulated Depreciation and Amortization	18,066	17,340	16,723	16,275	15,240
Total Property, Plant and Equipment – Net	$ 35,674	$ 34,344	$ 32,987	$ 29,870	$ 26,781
Total Assets	$ 50,455	$ 48,348	$ 45,155	$ 40,319	$ 37,877
Total AEP Common Shareholders’ Equity	$ 13,622	$ 13,140	$ 10,693	$ 10,079	$ 9,412
Noncontrolling Interests	$ -	$ -	$ 17	$ 18	$ 18
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 60	$ 61	$ 61	$ 61	$ 61
Long-term Debt (a)	$ 16,811	$ 17,498	$ 15,983	$ 14,994	$ 13,698
Obligations Under Capital Leases (a)	$ 474 (b)	$ 317	$ 325	$ 371	$ 291
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.40	$ 2.87	$ 2.52
Discontinued Operations, Net of Tax	-	-	0.03	0.06	0.02
Income Before Extraordinary Loss	2.53	2.97	3.43	2.93	2.54
Extraordinary Loss, Net of Tax	-	(0.01)	-	(0.20)	-
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.53	$ 2.96	$ 3.43	$ 2.73	$ 2.54
Weighted Average Number of Basic Shares Outstanding (in millions)	479	459	402	399	394
Market Price Range:					
High	$ 37.94	$ 36.51	$ 49.11	$ 51.24	$ 43.13
Low	$ 28.17	$ 24.00	$ 25.54	$ 41.67	$ 32.27
Year-end Market Price	$ 35.98	$ 34.79	$ 33.28	$ 46.56	$ 42.58
Cash Dividends Paid per AEP Common Share	$ 1.71	$ 1.64	$ 1.64	$ 1.58	$ 1.50
Dividend Payout Ratio	67.59%	55.41%	47.8%	57.9%	59.1%
Book Value per AEP Common Share	$ 28.32	$ 27.49	$ 26.35	$ 25.17	$ 23.73

(a) Includes portion due within one year.
(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We operate an extensive portfolio of assets including:

- Almost 39,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Approximately 220,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 9,000 railcars, approximately 3,300 barges, 62 towboats, 29 harbor boats and a coal handling terminal with 18 million tons of annual capacity).

Economic Conditions

Retail margins increased during 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout our service territories. Industrial sales increased 5% in 2010 in comparison to the recessionary lows of 2009. We forecast a 1% increase in commercial sales and 2% increases in both our residential and industrial sales in 2011 as a result of anticipated slow economic growth. Our forecasted industrial sales growth of 2% is due to the announcement of increased production by Ormet, a large aluminum manufacturer in Ohio, and announced expansions of several refineries in our Texas service territory.

Regulatory Activity

The table below summarizes our significant 2010 regulatory activities:

Jurisdiction	Annual Approved Base Rate Change	Annual Rider Surcharge Rate Change	Approved Return on Common Equity	Effective Date
	(in millions)			
Kentucky	$ 63.7	$ -	10.50%	July 2010
Michigan	35.7	3.3 (a)	10.35%	December 2010
Oklahoma	30.3	(30.3)	10.15%	February 2011
Texas	15.0	10.0 (b)	10.33%	May 2010
Virginia	61.5	-	10.53%	August 2010

(a) The MPSC granted I&M recovery of $6.6 million of customer choice implementation costs over a two year period beginning April 2011.
(b) The PUCT granted SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs which began in May 2010.

In Ohio, several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved 2009 – 2011 ESP rates. In January 2011, the PUCO issued an order that determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo 2009 earnings were significantly excessive. As a result, the PUCO ordered CSPCo to refund $43 million of its earnings to customers, which was recorded on CSPCo's December 2010 books. Also, in January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. Customer class rates individually vary, but on average, customers would experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

In West Virginia, a settlement agreement was filed with the WVPSC in December 2010 to increase annual base rates by $60 million, effective March 2011. The settlement agreement allows APCo to defer and amortize up to $18 million of previously expensed 2009 incremental storm expenses over a period of eight years. A decision from the WVPSC is expected in March 2011.

Cost Reduction Initiatives

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, the AEP System implemented cost reduction initiatives in the second quarter of 2010 to reduce its workforce by 11.5% and reduce Other Operation and Maintenance spending. Achieving these goals involved identifying process improvements, streamlining organizational designs and developing other efficiencies that will deliver additional savings. In 2010, we recorded $293 million of pretax expense related to these cost reduction initiatives. Starting with the third quarter of 2010, we realized cost savings in Other Operation and Maintenance expenses on our Consolidated Statements of Income and anticipate continued savings to help offset future inflationary impacts.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction, its approved wetlands and air permits and its transmission line certificate of environmental compatibility and public need. In 2010, the motions for preliminary injunction were partially granted and upheld on appeal pending a hearing. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. A hearing on SWEPCo's appeal is scheduled for March 2011.

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo related to the reversal of the APSC's earlier grant of a Certificate of Environmental Compatibility and Public Need (CECPN) for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant costs in Arkansas retail rates. The APSC issued an order which reversed and set aside the previously granted CECPN.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition. See "Turk Plant" section of Note 4.

Settlement with Bank of America

In February 2011, we reached a settlement with BOA and paid $425 million in full settlement of all claims against us. We also received title to 55 BCF of cushion gas in the Bammel storage facility as part of the settlement. The effect of the settlement had no impact on our financial statements for the year ended December 31, 2010. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As of December 31, 2010, approximately 5,000 Ohio retail customers (primarily CSPCo customers) have switched to alternative CRES providers. As a result, in comparison to 2009, we lost approximately $16 million of generation related gross margin in 2010 and currently forecast incremental lost margins of approximately $54 million for 2011. We anticipate recovery of a portion of this lost margin through off-system sales and our newly created CRES provider. Our CRES provider will target retail customers in Ohio, both within and outside of our retail service territory.

Termination of AEP Power Pool

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. The decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If members of the current AEP Power Pool experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Transmission Agreement

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The new Transmission Agreement will be phased-in for retail rates over periods of up to four years, adds KGPCo and WPCo as parties to the agreement and changes the allocation method. Our recovery mechanism for transmission costs is through our base rates. State regulatory phase-in of the new agreement may limit our ability to fully recover our transmission costs.

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 6.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See "Texas Restructuring Appeals" section of Note 4.

Mountaineer Carbon Capture and Storage

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In APCo's July 2009 Virginia base rate filing and May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the PVF costs, which resulted in a pretax write-off of approximately $54 million in the second quarter of 2010. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. A decision from the WVPSC is expected in March 2011. As of December 31, 2010, APCo has recorded a noncurrent regulatory asset of $60 million related to the PVF. If APCo cannot recover its remaining investments in and expenses related to the PVF, it would reduce future net income and cash flows and impact financial condition. See "Mountaineer Carbon Capture and Storage Project" section of Note 4.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of December 31, 2010, APCo has incurred $14 million in total costs and has received $5 million of DOE funding resulting in a net $9 million balance included in Construction Work In Progress on the Consolidated Balance Sheets. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows. See "Mountaineer Carbon Capture and Storage Project" section of Note 4.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our net income.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO_2 emissions to address concerns about global climate change.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. Notable developments in CAA regulatory requirements affecting our operations are discussed briefly below.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the D.C. Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. CAIR remains in effect while a new rulemaking is conducted. Nearly all of the states in which our power plants are located are covered by CAIR. In July 2010, the Federal EPA issued a proposed rule (Transport Rule) to replace CAIR that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO_2 and/or NO_x. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NO_x program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NO_x programs and an annual SO_2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately one million tons per year more SO_2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces SO_2 emissions by an additional 800,000 tons per year. The SO_2 and NO_x programs rely on newly-created allowances rather than relying on the CAIR NO_x allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and stringency of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers, as these features could accelerate unit retirements, increase capital requirements, constrain operations, decrease reliability and unfavorably impact financial condition if the increased costs are not recovered in rates or market prices. The Federal EPA requested comments on a scheme based exclusively on intrastate trading of allowances or a scheme that establishes unit-by-unit emission rates. Either of these options would provide less flexibility and exacerbate the negative impact of the rule. The proposal indicates that the requirements are expected to be finalized in June 2011 and be effective January 1, 2012.

The Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new state implementation plans (SIPs) including mercury requirements for existing coal-fired power plants. The CAMR was vacated and remanded to the Federal EPA by the D.C. Circuit Court of Appeals in 2008.

Under the terms of a consent decree, the Federal EPA is required to issue final maximum achievable control technology (MACT) standards for coal and oil-fired power plants by November 2011. The Federal EPA has substantial discretion in determining how to structure the MACT standards. We will urge the Federal EPA to carefully consider all of the options available so that costly and inefficient control requirements are not imposed regardless of unit size, age or other operating characteristics. However, we have approximately 5,000 MW of older coal units, including 2,000 MW of older coal-fired capacity already subject to control requirements under the NSR consent decree, for which it may be economically inefficient to install scrubbers or other environmental controls. The timing and ultimate disposition of those units will be affected by: (a) the MACT standards and other environmental regulations, (b) the economics of maintaining the units, (c) demand for electricity, (d) availability and cost of replacement power and (e) regulatory decisions about cost recovery of the remaining investment in those units.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual SIPs or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA has proposed disapproval of SIPs in a few states, and proposed more stringent control requirements for affected units in those states. If the Federal EPA takes such action in the states where our facilities are located, it could increase the costs of compliance, accelerate the installation of required controls, and/or force the premature retirement of existing units.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009 and final rules limiting CO_2 emissions from new motor vehicles in May 2010. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units and announced a settlement agreement to issue proposed new source performance standards for utility boilers. It is not possible at this time to estimate the costs of compliance with these new standards, but they may be material.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_x and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Estimated Air Quality Environmental Investments

The CAIR, CAVR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. Our estimates are subject to significant uncertainties and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: (a) the timing of implementation, (b) required levels of reductions, (c) methods for allocation of allowances and (d) our selected compliance alternatives and their costs. These obligations may also be affected or altered by the development of new regulations described above. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

The CAIR, CAVR and commitments in the consent decree will require installation of additional controls on our power plants through 2020. We plan to install additional scrubbers on 6,770 MW for SO_2 control. From 2011 to 2020, we estimate total environmental investment to meet these requirements of \$10.6 billion including investment in scrubbers and other SO_2 equipment of approximately \$5.9 billion. These estimates are highly uncertain due to the variability associated with: (a) the states' implementation of these regulatory programs, including the potential for SIPs or FIPS that impose standards more stringent than CAIR or CAVR, (b) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments and (f) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant. Estimated construction expenditures are subject to periodic review and modification.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates. We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future net income, cash flows and possibly financial condition.

Coal Combustion Residual Rule

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

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities. We estimate that the potential compliance costs associated with the proposed solid waste management alternative could be as high as $3.9 billion for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, these costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

National public policy makers and regulators in the 11 states we serve have conflicting views on global warming. We are focused on taking, in the short term, actions that we see as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

We believe that this is a global issue and that the United States should assume a leadership role in developing a new international approach that will address growing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2 in this discussion) from all nations, including developing countries. We support a reasonable approach to CO_2 emission reductions that recognizes a reliable and affordable electric supply is vital to economic stability and that allows sufficient time for technology development. We proposed to national policy makers that national and international policy for reasonable CO_2 controls should involve the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy CO_2 reduction technologies
- Removal of regulatory or economic barriers to CO_2 emission reductions
- Recognition for early actions/investments in CO_2 reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

For additional information on global warming, see Part I of the Annual Report under the headings entitled "Business – General – Environmental and Other Matters – Global Warming."

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA discussed above.

Our fossil fuel-fired generating units are very large sources of CO_2 emissions. If substantial CO_2 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 CO_2 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 and natural gas based generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain 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. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power by an additional 2,000 MW from 2007 levels by 2011. By the end of 2010, we secured, through power purchase agreements, an additional 1,111 MW of wind power. To the extent demand for renewable energy from wind power increases, it could have a positive effect on future earnings from our transmission activities. For example, a project in Texas would build new transmission lines to transport electricity from planned wind energy generation in west Texas to more densely populated areas in eastern Texas.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participated in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. Through the end of 2009, we reduced our emissions by a cumulative 94 million metric tons from adjusted baseline levels in 1998 through 2001 as a result of these voluntary actions. Our total CO_2 emissions in 2009 were 136 million metric tons. We estimate that our 2010 emissions were approximately 140 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 6.

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

Global warming creates the potential for physical and financial risk. The materiality of the risks depends on whether any physical changes occur quickly or over several decades and the extent and nature of those changes. Physical risks from climate change could include changes in weather conditions. Our customers' energy needs currently vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling today represent their largest energy use. To the extent weather patterns change significantly, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes could require us to invest in more generating assets, transmission and other infrastructure to serve increased load, driving the overall cost of electricity higher. Decreased energy use due to weather changes could affect our financial condition through lower sales and decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions and increased storm restoration costs. We may not recover all costs related to mitigating these physical and financial risks. Weather conditions outside of our service territory could also have an impact on our revenues, either directly through changes in the patterns of our off-system power purchases and sales or indirectly through demographic changes as people adapt to changing weather. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales.

To the extent climate change impacts a region's economic health, it could also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

RESULTS OF OPERATIONS

SEGMENTS

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 and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Utility Operations

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

AEP River Operations

- Commercial barging operations that annually transport approximately 39 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 46% of the barging is for transportation of agricultural products, 25% for coal, 11% for steel and 18% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT and to a lesser extent Ohio in PJM and MISO.

The table below presents our consolidated Income (Loss) Before Discontinued Operations and Extraordinary Loss by segment for the years ended December 31, 2010, 2009 and 2008.

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in millions)	
Utility Operations	$ 1,201	$ 1,329	$ 1,123
AEP River Operations	37	47	55
Generation and Marketing	25	41	65
All Other (a)	(45)	(47)	133
Income Before Discontinued Operations and Extraordinary Loss	$ 1,218	$ 1,370	$ 1,376

(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.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- 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 settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss in 2010 decreased $152 million compared to 2009 primarily due to $185 million of charges incurred (net of tax) related to cost reduction initiatives. In 2010, we conducted cost reduction initiatives to reduce both labor and non-labor expenses.

Average basic shares outstanding increased to 479 million in 2010 from 459 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 481 million as of December 31, 2010.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $6 million compared to 2008 primarily due to income in 2008 from the cash settlement of a purchase power and sale agreement with TEM offset by an increase in income from our Utility Operations segment. The increase in Utility Operations segment net income primarily relates to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower industrial sales as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 459 million in 2009 from 402 million in 2008 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 478 million as of December 31, 2009.

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 total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in millions)	
Total Revenues	$ 13,791	$ 12,803	$ 13,566
Fuel and Purchased Power	4,996	4,420	5,622
Gross Margin	8,795	8,383	7,944
Depreciation and Amortization	1,598	1,561	1,450
Other Operating Expenses	4,573	4,162	4,114
Operating Income	2,624	2,660	2,380
Other Income, Net	169	138	173
Interest Expense	942	916	915
Income Tax Expense	650	553	515
Income Before Discontinued Operations and Extraordinary Loss	$ 1,201	$ 1,329	$ 1,123

KWH Sales/Degree Days

Summary of KWH Energy Sales for Utility Operations

	Years Ended December 31, 2010	2009	2008
	(in millions of KWH)		
Retail:			
Residential	61,944	58,232	58,892
Commercial	50,748	49,925	50,382
Industrial	57,333	54,428	64,508
Miscellaneous	3,083	3,048	3,114
Total Retail (a)	173,108	165,633	176,896
Wholesale	32,581	29,670	43,068
Total KWHs	205,689	195,303	219,964

(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

	Years Ended December 31, 2010	2009	2008
	(in degree days)		
Eastern Region			
Actual - Heating (a)	3,222	3,018	3,154
Normal - Heating (b)	2,983	3,040	3,018
Actual - Cooling (c)	1,307	816	949
Normal - Cooling (b)	1,002	1,011	986
Western Region			
Actual - Heating (a)	1,112	970	992
Normal - Heating (b)	980	984	1,010
Actual - Cooling (d)	2,515	2,439	2,252
Normal - Cooling (b)	2,339	2,344	2,320

(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.

2010 Compared to 2009

Reconciliation of Year Ended December 31, 2009 to Year Ended December 31, 2010
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2009	$	1,329
Changes in Gross Margin:		
Retail Margins		601
Off-system Sales		53
Transmission Revenues		15
Other Revenues		(257)
Total Change in Gross Margin		412
Total Expenses and Other:		
Other Operation and Maintenance		(351)
Depreciation and Amortization		(37)
Taxes Other Than Income Taxes		(60)
Interest and Investment Income		5
Carrying Costs Income		23
Allowance for Equity Funds Used During Construction		(5)
Interest Expense		(26)
Equity Earnings of Unconsolidated Subsidiaries		8
Total Expenses and Other		(443)
Income Tax Expense		(97)
Year Ended December 31, 2010	$	1,201

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 $601 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $138 million increase in the recovery of E&R costs in Virginia, costs related to the Transmission Rate Adjustment Clause in Virginia and construction financing costs in West Virginia.
    - A $49 million increase in the recovery of advanced metering costs in Texas.
    - A $43 million net rate increase for KPCo.
    - A $42 million net rate increase for SWEPCo.
    - A $39 million net rate increase for I&M.
    - A $37 million net rate increase for PSO.
    - A $14 million net rate increase in our other jurisdictions.
    - For the increases described above, $183 million of these increases relate to riders/trackers which have corresponding increases in other expense items.
  - A $229 million increase in weather-related usage primarily due to a 60% increase in cooling degree days in our eastern service territory and 7% and 15% increases in heating degree days in our eastern and western service territories, respectively.
  - A $78 million increase due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase was offset by a corresponding decrease in Other Revenues as discussed below.

  These increases were partially offset by:
  - A $43 million decrease due to a refund provision for the 2009 Significantly Excessive Earnings Test (SEET).
  - A $38 million decrease due to the termination of an I&M unit power agreement.

- **Margins from Off-system Sales** increased $53 million primarily due to increased prices and higher physical sales volumes in our eastern service territory, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $15 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- **Other Revenues** decreased $257 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $78 million in 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above. Other Revenues also decreased due to lower gains on sales of emission allowances of $29 million, partially offset by sharing with customers in certain fuel clauses. This decrease in gains on sales of emission allowances was the result of lower market prices.

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

- **Other Operation and Maintenance** expenses increased $351 million primarily due to the following:
  - A $280 million increase due to expenses related to the cost reduction initiatives. In 2010, management conducted cost reduction initiatives to reduce both labor and non-labor expenses.
  - A $114 million increase in demand side management, energy efficiency and vegetation management programs and other related expenses. All of these expenses are currently recovered dollar-for-dollar in rate recovery riders/trackers in Gross Margin.
  - A $54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.

  These increases were partially offset by:
  - An $89 million decrease in storm expenses.
- **Depreciation and Amortization** increased $37 million primarily due to new environmental improvements placed in service at APCo, CSPCo and OPCo and placing the Stall Unit in service at SWEPCo partially offset by lower depreciation in Arkansas and Texas as a result of SWEPCo's recent base rate orders.
- **Taxes Other Than Income Taxes** increased $60 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives and higher franchise and property taxes.
- **Carrying Costs Income** increased $23 million primarily due to environmental construction in Virginia and a higher under-recovered fuel balance for OPCo.
- **Interest Expense** increased $26 million primarily due to an increase in long-term debt and a decrease in the debt component of AFUDC due to completed environmental improvements at APCo, CSPCo and OPCo.
- **Income Tax Expense** increased $97 million 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 prescription drug benefits, partially offset by a decrease in pretax book income.

2009 Compared to 2008

Reconciliation of Year Ended December 31, 2008 to Year Ended December 31, 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2008	$	1,123
Changes in Gross Margin:		
Retail Margins		549
Off-system Sales		(333)
Transmission Revenues		25
Other Revenues		198
Total Change in Gross Margin		439
Total Expenses and Other:		
Other Operation and Maintenance		(46)
Depreciation and Amortization		(111)
Taxes Other Than Income Taxes		(2)
Interest and Investment Income		(38)
Carrying Costs Income		(36)
Allowance for Equity Funds Used During Construction		37
Interest Expense		(1)
Equity Earnings of Unconsolidated Subsidiaries		2
Total Expenses and Other		(195)
Income Tax Expense		(38)
Year Ended December 31, 2009	$	1,329

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 $549 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $187 million increase related to the PUCO's approval of our Ohio ESPs.
    - A $170 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia.
    - A $75 million net rate increase for PSO.
    - A $42 million net rate increase for I&M.
    - A $50 million net rate increase in our other jurisdictions.
  - A $201 million increase in fuel margins in Ohio primarily due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the deferral of fuel and related costs related to the ESP period.
  - A $102 million increase due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.
  - A $68 million increase due to lower PJM and other costs as the result of lower generation sales.

  These increases were partially offset by:
  - A $214 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
  - A $78 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
  - A $52 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days in our eastern service territory.
  - A $29 million decrease related to favorable coal contract amendments in 2008.

- **Margins from Off-system Sales** decreased $333 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading and marketing margins.
- **Transmission Revenues** increased $25 million primarily due to increased rates in the ERCOT and SPP regions.
- **Other Revenues** increased $198 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $78 million in 2009 for the cost of replacement power resulting during the outage period. This decrease in insurance proceeds 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 $46 million primarily due to the following:
  - The 2008 deferral of $74 million of previously expensed Oklahoma ice storm costs resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $64 million increase in administrative and general expenses primarily for employee benefits.
  - A $48 million increase in storm restoration expenses due to the December 2009 winter storm in Tennessee, Virginia and West Virginia.
  - A $32 million increase in demand side management, energy efficiency and vegetation management programs.
  - A $29 million increase in recoverable transmission service expenses.
  - A $14 million increase due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.

  These increases were partially offset by:
  - A $67 million decrease in distribution and customer account expenses.
  - A $51 million decrease in transmission expenses related to cost recovery rider amortization in Ohio and rate adjustment clause deferrals in Virginia.
  - A $43 million decrease in other operating expenses including lower charitable contributions.
  - A $39 million decrease in RTO fees, forestry and other transmission expenses.
  - A $15 million decrease in plant outages and other plant operating and maintenance expenses, including lower removal costs.
- **Depreciation and Amortization** increased $111 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- **Interest and Investment Income** decreased $38 million primarily due to lower interest income related to federal income tax refunds filed with the IRS and the recognition of other-than-temporary losses related to equity investments held by our protected cell of EIS in 2009.
- **Carrying Costs Income** decreased $36 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- **Allowance for Equity Funds Used During Construction** increased $37 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective the second quarter of 2009.
- **Interest Expense** increased $1 million primarily due to a $52 million increase in interest expense related to increased long-term debt borrowings partially offset by interest expense of $47 million recorded in 2008 related to the 2008 SIA adjustment for off-system sales margins in accordance with the FERC's 2008 order.
- **Income Tax Expense** increased $38 million primarily due to an increase in pretax book income offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

AEP RIVER OPERATIONS

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $47 million in 2009 to $37 million in 2010 primarily due to expenses related to cost reduction initiatives, increased interest expense on new equipment financing, a property casualty loss in 2010 and a gain on the sale of two older towboats in 2009.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $55 million in 2008 to $47 million in 2009 primarily due to lower revenues as a result of a weak import market.

GENERATION AND MARKETING

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $41 million in 2009 to $25 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities, reduced plant performance due to lower power prices in ERCOT, partially offset by positive hedging activities on our generation assets and increased income from our wind farm operations.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $65 million in 2008 to $41 million in 2009 primarily due to lower gross margins at the Oklaunion Generating Station as a result of lower power prices in ERCOT and decreased generation from our wind farm operations.

ALL OTHER

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from All Other increased from a loss of $47 million in 2009 to a loss of $45 million in 2010 primarily due to gains on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) and a decrease in various parent related expenses partially offset by a contribution to AEP's charitable foundation and losses on the sales of assets.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $133 million in 2008 to a loss of $47 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

AEP SYSTEM INCOME TAXES

2010 Compared to 2009

Income Tax Expense increased $68 million in comparison to 2009 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, offset in part by a decrease in pretax book income.

2009 Compared to 2008

Income Tax Expense decreased $67 million in comparison to 2008 primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. Target debt to equity ratios are usually maintained for each subsidiary and often credit arrangements contain ratios as covenants that must be met for borrowing to continue.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31, 2010		December 31, 2009	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 16,811	52.8 %	$ 17,498	56.8 %
Short-term Debt	1,346	4.2	126	0.4
Total Debt	18,157	57.0	17,624	57.2
Preferred Stock of Subsidiaries	60	0.2	61	0.2
AEP Common Equity	13,622	42.8	13,140	42.6
Total Debt and Equity Capitalization	$ 31,839	100.0 %	$ 30,825	100.0 %

Our ratio of debt-to-total capital decreased from 57.2% in 2009 to 57% in 2010 primarily due to an increase in common equity.

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 December 31, 2010, we had $3.4 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2010, our available liquidity was approximately $2.5 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,454	April 2012
Revolving Credit Facility	1,500	June 2013
Revolving Credit Facility	478	April 2011
Total	3,432	
Cash and Cash Equivalents	294	
Total Liquidity Sources	3,726	
Less: AEP Commercial Paper Outstanding	650	
Letters of Credit Issued	601	
Net Available Liquidity	$ 2,475	

We have credit facilities totaling $3.4 billion, of which two $1.5 billion credit facilities support our commercial paper program. In June 2010, we terminated one of the $1.5 billion credit facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013. These credit facilities also allow us to issue letters of credit in an amount up to $1.35 billion. In June 2010, we also reduced the credit facility that matures in April 2011 from $627 million to $478 million. This facility is fully utilized for letters of credit providing liquidity support for Pollution Control Bonds. In March 2011, we intend to replace the revolving credit facility of $478 million with bilateral letters of credit or refinance the bonds. We may redeem some portion of the Pollution Control Bonds supported by the facility.

We use our commercial paper program to meet the short-term borrowing needs of the subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2010 was $868 million. The weighted-average interest rate for our commercial paper during 2010 was 0.43%.

Securitized Accounts Receivables

In 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013. We intend to extend or replace the agreement expiring in July 2011 on or before its maturity.

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 outstanding debt and capitalization is contractually defined in our revolving credit agreements. At December 31, 2010, this contractually-defined percentage was 53.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. At December 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 December 31, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.46 per share in January 2011. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

We do not believe restrictions related to our various financing arrangements, charter provisions and regulatory requirements will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

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

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 490	$ 411	$ 178
Net Cash Flows from Operating Activities	2,662	2,475	2,581
Net Cash Flows Used for Investing Activities	(2,523)	(2,916)	(4,027)
Net Cash Flows from (Used for) Financing Activities	(335)	520	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	(196)	79	233
Cash and Cash Equivalents at End of Period	$ 294	$ 490	$ 411

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

Operating Activities

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Income	$ 1,218	$ 1,365	$ 1,388
Depreciation and Amortization	1,641	1,597	1,483
Other	(197)	(487)	(290)
Net Cash Flows from Operating Activities	$ 2,662	$ 2,475	$ 2,581

Net Cash Flows from Operating Activities were $2.7 billion in 2010 consisting primarily of Net Income of $1.2 billion and $1.6 billion 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. 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. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to a change in tax versus book temporary differences from operations. Accrued Taxes, Net increased primarily as a result of the receipt of a federal income tax refund of $419 million related to a net operating loss in 2009 that was carried back to 2007 and 2008. We also contributed $500 million to our qualified pension trust in 2010.

Net Cash Flows from Operating Activities were $2.5 billion in 2009 consisting primarily of Net Income of $1.4 billion and $1.6 billion of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity, an increase in under-recovered fuel primarily in Ohio and West Virginia and an increase in accrued tax benefits resulting from a net income tax operating loss in 2009. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a one-time change in tax accounting method and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Net Income of $1.4 billion and $1.5 billion 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. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, materials and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.

Investing Activities

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Construction Expenditures	$ (2,345)	$ (2,792)	$ (3,800)
Acquisitions of Nuclear Fuel	(91)	(169)	(192)
Acquisitions of Assets	(155)	(104)	(160)
Proceeds from Sales of Assets	187	278	90
Other	(119)	(129)	35
Net Cash Flows Used for Investing Activities	$ (2,523)	$ (2,916)	$ (4,027)

Net Cash Flows Used for Investing Activities were $2.5 billion in 2010 primarily due to Construction Expenditures for environmental, new generation, distribution and transmission investments. Proceeds from Sales of Assets in 2010 include $139 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners as planned and $95 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investments.

Financing Activities

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Issuance of Common Stock, Net	$ 93	$ 1,728	$ 159
Issuance/Retirement of Debt, Net	497	(360)	2,266
Dividends Paid on Common Stock	(824)	(758)	(666)
Other	(101)	(90)	(80)
Net Cash Flows from (Used for) Financing Activities	$ (335)	$ 520	$ 1,679

Net Cash Flows Used for Financing Activities were $335 million in 2010. Our net debt issuances were $497 million. The net issuances included issuances of $952 million of notes and $326 million of pollution control bonds, a $531 million increase in commercial paper outstanding and retirements of $1.6 billion of notes, $148 million of securitization bonds and $222 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 $824 million.

Net Cash Flows from Financing Activities were $520 million in 2009. Issuance of Common Stock, Net of $1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $360 million. The net retirements included the repayment of $2 billion outstanding under our credit facilities and retirement of $816 million of long-term debt and issuances of $1.9 billion of senior unsecured and debt notes and $431 million of pollution control bonds. We paid common stock dividends of $758 million.

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity during the 2008 credit market. We paid common stock dividends of $666 million.

The following financing activities occurred during 2010:

AEP Common Stock:

- During 2010, we issued 3 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $93 million.

Debt:

- During 2010, we issued approximately $1.3 billion of long-term debt, including $650 million of senior notes at interest rates ranging from 3.4% to 6.2%, $150 million of senior notes at a variable interest rate, $326 million of pollution control revenue bonds at interest rates ranging from 2.875% to 5.375%, $84 million of notes at a 4% interest rate and $68 million of notes at a variable interest rate. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2010, we entered into $1 billion of interest rate derivatives and settled $172 million of such transactions. The settlements resulted in net cash payments of $6 million. As of December 31, 2010, we had in place $907 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2011:

- In January 2011, TCC retired $92 million of its outstanding Securitization Bonds.
- In January 2011, PSO issued $250 million of 4.4% Senior Unsecured Notes due 2021.
- In January 2011, PSO gave notice to retire $200 million of 6% Senior Unsecured Notes due in 2032 on February 28, 2011.
- In February 2011, APCo issued $65 million of 2% Pollution Control Bonds due 2041 with a 2012 mandatory put date.
- We expect to refinance approximately $1 billion of the $1.3 billion of long-term debt that will mature in 2011.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $2.5 billion and $2.6 billion of construction expenditures excluding AFUDC and capitalized interest for 2011 and 2012, respectively. For 2012 through 2014, we forecast annual construction expenditures to average between $2.6 billion and $3.1 billion. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The estimated expenditures include amounts for completion of the Turk and Dresden Plants. Both plants are scheduled for completion in 2012. We resumed work on Dresden in the first quarter of 2011. The 2011 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	Budgeted Construction Expenditures (in millions)
Environmental	$ 223
Generation	813
Transmission	594
Distribution	776
Other	100
Total	$ 2,506

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:

AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under this agreement, AEP Credit securitizes an interest in a portion of the receivables it acquires from affiliated utilities with the bank conduits and receives cash. Effective January 1, 2010, we record the receivables and debt related to AEP Credit on our Consolidated Balance Sheet.

At December 31, 2009, AEP Credit had $631 million of securitized receivables outstanding. See “ASU 2009-16 ‘Transfers and Servicing’ (ASU 2009-16)” section of Note 2.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $887 million as of December 31, 2010.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $36 million for the remaining railcars as of December 31, 2010. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five year renewal. At December 31, 2010, the maximum potential loss was approximately $25 million ($17 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.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2010:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Short-term Debt (a)	$ 1,346	$ -	$ -	$ -	$ 1,346
Interest on Fixed Rate Portion of Long-term Debt (b)	909	1,709	1,467	7,778	11,863
Fixed Rate Portion of Long-term Debt (c)	752	2,009	2,431	10,947	16,139
Variable Rate Portion of Long-term Debt (d)	557	150	-	-	707
Capital Lease Obligations (e)	100	159	106	286	651
Noncancelable Operating Leases (e)	306	547	467	1,349	2,669
Fuel Purchase Contracts (f)	2,810	3,974	2,543	3,718	13,045
Energy and Capacity Purchase Contracts (g)	69	199	204	1,101	1,573
Construction Contracts for Capital Assets (h)	1,031	1,407	1,636	3,143	7,217
Total	$ 7,880	$ 10,154	$ 8,854	$ 28,322	$ 55,210

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2010 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.29% and 1.31% at December 31, 2010.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $119 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2010, we expect to make contributions to our pension plans totaling $158 million in 2011. Estimated contributions of $158 million in 2012 and $158 million in 2013 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 80.3% funded as of December 31, 2010.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2010, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 601	$ -	$ -	$ -	$ 601
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	1,457	18	20	41	1,536
Total Commercial Commitments	$ 2,058	$ 18	$ 20	$ 106	$ 2,202

(a) 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, debt service reserves and variable rate Pollution Control Bonds. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $601 million with maturities ranging from January 2011 to November 2011. See "Letters of Credit" section of Note 6.

(b) See "Guarantees of Third-Party Obligations" section of Note 6.

(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs, expanded tax credits and extended the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The Small Business Jobs Act, enacted in September 2010, included a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreasing the deduction to 50% for 2012.

These enacted provisions will have no material impact on net income or financial condition but will have a favorable impact on cash flows in 2011 and are expected to result in material future cash flow benefits.

TRANSMISSION INITIATIVES

AEP Transmission Company, LLC (Utility Operations segment)

In 2006, we formed AEP Transmission Company, LLC (AEP Transco). In 2009, AEP Transco formed seven wholly-owned transmission companies. Upon approval of FERC interim rates, the transmission companies began recognizing revenues in July 2010 for their respective investments in PJM and SPP. The transmission companies have been established in Ohio, Oklahoma and Michigan. Applications for establishment of AEP Kentucky Transmission Company, Inc. and AEP West Virginia Transmission Company, Inc. have been filed with the KPSC and the WVPSC, respectively, and are pending approval. Other filings with commissions will be made in 2011. These seven companies consist of:

AEP East Transmission companies:

- AEP Appalachian Transmission Company, Inc. (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc.
- AEP Kentucky Transmission Company, Inc.
- AEP Ohio Transmission Company, Inc.
- AEP West Virginia Transmission Company, Inc.

AEP West Transmission companies:

- AEP Oklahoma Transmission Company, Inc.
- AEP Southwestern Transmission Company, Inc. (covering Arkansas and Louisiana)

AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements. Therefore, the transmission companies do not have any employees.

AEP Transco owns all of the transmission companies' equity. The transmission companies do not have outstanding debt and have not received capital contributions. All of the transmission companies' capital needs are provided by Parent and AEP Transco. For the transmission companies listed above, we forecast approximately $160 million of construction expenditures for 2011.

Joint Venture Initiatives (Utility Operations segment)

We are currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Equity Method Investment at December 31, 2010	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2017	MEHC Texas Transco, LLC (50%) AEP (50%)	$ 3,100,000 (a)	$ 110,323	9.96 %
PATH (b)	West Virginia	2015 (c)	Allegheny Energy (50%) AEP (50%)	2,100,000 (d)	23,621	14.3 % (e)
Prairie Wind	Kansas	2014	Westar Energy (50%) ETA (50%) (f)	225,000	784	12.8 %
Pioneer	Indiana	2016	Duke Energy (50%) AEP (50%)	1,000,000	-	12.54 %

(a) In addition to ETT's current total estimated project costs of $3.1 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis.
(b) In September 2007, AEP Transmission Holding Company, LLC and AET PATH Company, LLC, a subsidiary of Allegheny Energy, Inc., formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH) and its subsidiaries. The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM.
(c) PJM has directed the construction of the PATH Project and placement of the project into service by June 2015, at the latest.
(d) PATH consists of the "West Virginia Series," which is owned equally by subsidiaries of Allegheny Energy Inc. and AEP, and the "Allegheny Series" which is wholly-owned by a subsidiary of Allegheny Energy Inc. The total project is estimated to cost approximately $2.1 billion. Our estimated share of the project cost is approximately $700 million. In February 2011, the "Ohio Series" was dissolved, which was owned equally by subsidiaries of Allegheny Energy Inc. and AEP.
(e) An October 2010 FERC order set the 14.3% return on equity for hearing.
(f) Electric Transmission America, LLC (ETA) is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) America Transco, LLC and AEP Transmission Holding Company, LLC. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP Transmission Holding Company, LLC owns 25% of Prairie Wind through its ownership interest in ETA.

For our joint ventures listed above, we forecast approximately $113 million of equity contributions in 2011 to support construction and other expenditures.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, CSPCo, through its ownership of Conesville Coal Preparation Company (CCPC), and OPCo, through its use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC, CCPC and Conner Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended December 31, 2010:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	1	-	-
Number of Orders Issued under 104(b) *	-	-	-
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *	-	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-
Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ 1,026	$ -	$ -
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has two legal actions pending before the Mine Safety and Health Administration (MSHA) challenging four violations issued by MSHA following an employee fatality in March 2009.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP’s Board of Directors and the Audit Committee reviews the disclosure relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $46 million, $55 million and $72 million for the years ended December 31, 2010, 2009 and 2008, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $549 million and $503 million as of December 31, 2010 and 2009, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets as approved by our regulators. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. We perform depreciation studies to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

	Years Ended December 31,		
Net Periodic Benefit Cost	**2010**	**2009**	**2008**
		(in millions)	
Pension Plans	$ 141	$ 96	$ 51
Postretirement Plans	111	141	80

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2011, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 7.75% for the Qualified Plan and 7.5% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2011 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2011 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	50 %	9.00 %	66 %	9.00 %
Real Estate	5 %	7.60 %	-%	- %
Fixed Income	39 %	5.75 %	32 %	5.75 %
Other Investments	5 %	10.50 %	-%	- %
Cash and Cash Equivalents	1 %	3.00 %	2 %	3.00 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 7.75% for the Pension Plan and 7.5% for the Postretirement Plans are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Pension Plan's assets had an actual gain of 13.4% and 17.1% for the years ended December 31, 2010 and 2009, respectively. The Postretirement Plans' assets had an actual gain of 11.3% and 23.7% for the years ended December 31, 2010 and 2009, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2010, we had cumulative losses of approximately $285 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate at December 31, 2010 under this method was 5.05% for the Qualified Plan, 4.95% for the Nonqualified Plans and 5.25% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 7.75%, discount rates of 5.05% and 4.95% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $144 million, $166 million and $194 million in 2011, 2012 and 2013, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7.5%, a discount rate of 5.25% and various other assumptions, we estimate costs will approximate $82 million, $78 million and $74 million in 2011, 2012 and 2013, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of the Pension Plan's assets increased to $3.9 billion at December 31, 2010 from $3.4 billion at December 31, 2009 primarily due to a $500 million contribution. During 2010, the Qualified Plan paid $465 million and the Nonqualified Plans paid $15 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.5 billion at December 31, 2010 from $1.3 billion at December 31, 2009 primarily due to investment gains and contributions. The Postretirement Plans paid $142 million in benefits to plan participants during 2010.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Rate of compensation increase
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		**Other Postretirement Benefit Plans**	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2010 Benefit Obligations				
Discount Rate	$ (233)	$ 256	$ (132)	$ 147
Compensation Increase Rate	11	(10)	-	-
Cash Balance Crediting Rate	43	(38)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	114	(101)
Effect on 2010 Periodic Cost				
Discount Rate	(20)	22	(12)	14
Compensation Increase Rate	4	(3)	1	(1)
Cash Balance Crediting Rate	10	(9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(16)
Expected Return on Plan Assets	(20)	20	(6)	6

N/A Not Applicable

Nuclear Trust Funds

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.

We maintain trust funds 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. We record securities held in these trust funds as Spent Nuclear Fuel and

Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in these 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. See "Investments Held in Trust for Future Liabilities" section of Note 1 and "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11.

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2010

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

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

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET AND CREDIT RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and transacts in wholesale electricity, coal and emission allowance trading and marketing contracts. 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 and to a lesser extent Ohio in PJM and MISO, primarily transacts in wholesale energy 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 President, 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)
Year Ended December 31, 2010

	Utility Operations	Generation and Marketing	All Other	Total
		(in millions)		
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	(81)	(16)	5	(92)
Fair Value of New Contracts at Inception When Entered During the Period (a)	17	8	-	25
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	(1)	-	-	(1)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	(2)	(2)	-	(4)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	6	3	-	9
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	18	-	-	18
Total MTM Risk Management Contract Net Assets at December 31, 2010	$ 91	$ 140	$ 2	233
Commodity Cash Flow Hedge Contracts				11
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				21
Fair Value Hedge Contracts				6
Collateral Deposits				101
Total MTM Derivative Contract Net Assets at December 31, 2010				$ 372

(a) Reflects fair value on primarily 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 Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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 December 31, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 5.3%, 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 December 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	$ 666	$ 19	$ 647	1	$ 189
Split Rating	2	-	2	1	2
Noninvestment Grade	4	3	1	2	1
No External Ratings:					
Internal Investment Grade	215	-	215	2	123
Internal Noninvestment Grade	59	11	48	1	32
Total as of December 31, 2010	$ 946	$ 33	$ 913	7	$ 347
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 December 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 trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended December 31, 2010				Twelve Months Ended December 31, 2009			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
(in millions)				(in millions)			
$-	$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 movements 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 our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2010 and 2009, the estimated EaR on our debt portfolio for the following twelve months was $5 million and $4 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, changes in equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Accounting Standards Update No. 2009-16, *Transfers and Servicing (Topic 860): Accounting for Transfers of Financial Assets*, effective January 1, 2010.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company and our report dated February 25, 2011 expressed an unqualified opinion on those financial statements and included an explanatory paragraph relating to the Company's adoption of a new accounting pronouncement.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15 (f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2010.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009 and 2008
(in millions, except per-share and share amounts)

	2010	2009	2008
REVENUES			
Utility Operations	$ 13,687	$ 12,733	$ 13,326
Other Revenues	740	756	1,114
TOTAL REVENUES	14,427	13,489	14,440
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,029	3,478	4,474
Purchased Electricity for Resale	1,000	1,053	1,281
Other Operation	3,132	2,620	2,856
Maintenance	1,142	1,205	1,053
Gain on Settlement of TEM Litigation	-	-	(255)
Depreciation and Amortization	1,641	1,597	1,483
Taxes Other Than Income Taxes	820	765	761
TOTAL EXPENSES	11,764	10,718	11,653
OPERATING INCOME	2,663	2,771	2,787
Other Income (Expense):			
Interest and Investment Income	38	11	57
Carrying Costs Income	70	47	83
Allowance for Equity Funds Used During Construction	77	82	45
Interest Expense	(999)	(973)	(957)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,849	1,938	2,015
Income Tax Expense	643	575	642
Equity Earnings of Unconsolidated Subsidiaries	12	7	3
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,218	1,370	1,376
DISCONTINUED OPERATIONS, NET OF TAX	-	-	12
INCOME BEFORE EXTRAORDINARY LOSS	1,218	1,370	1,388
EXTRAORDINARY LOSS, NET OF TAX	-	(5)	-
NET INCOME	1,218	1,365	1,388
Less: Net Income Attributable to Noncontrolling Interests	4	5	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,214	1,360	1,383
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,211	$ 1,357	$ 1,380
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	479,373,306	458,677,534	402,083,847
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.40
Discontinued Operations, Net of Tax	-	-	0.03
Income Before Extraordinary Loss	2.53	2.97	3.43
Extraordinary Loss, Net of Tax	-	(0.01)	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.43
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	479,601,442	458,982,292	403,640,708
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.39
Discontinued Operations, Net of Tax	-	-	0.03
Income Before Extraordinary Loss	2.53	2.97	3.42
Extraordinary Loss, Net of Tax	-	(0.01)	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.42
CASH DIVIDENDS PAID PER SHARE	$ 1.71	$ 1.64	$ 1.64

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2010, 2009 and 2008
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 18	$ 10,097
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $6				(10)			(10)
Adoption of Guidance for Fair Value Accounting, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	4	28	131				159
Reissuance of Treasury Shares			40				40
Common Stock Dividends				(660)		(6)	(666)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							9,620
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $9					(16)		(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12		12
Pension and OPEB Funded Status, Net of Tax of $161					(298)		(298)
NET INCOME				1,383		5	1,388
TOTAL COMPREHENSIVE INCOME							1,090
TOTAL EQUITY – DECEMBER 31, 2008	426	2,771	4,527	3,847	(452)	17	10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $6					11		11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8					15		15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13					23		23
Pension and OPEB Funded Status, Net of Tax of $12					22		22
NET INCOME				1,360		5	1,365
TOTAL COMPREHENSIVE INCOME							1,443
TOTAL EQUITY – DECEMBER 31, 2009	498	3,239	5,824	4,451	(374)	-	13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
SUBTOTAL – EQUITY							12,411
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $14					26		26
Securities Available for Sale, Net of Tax of $4					(8)		(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $12					22		22
Pension and OPEB Funded Status, Net of Tax of $25					(47)		(47)
NET INCOME				1,214		4	1,218
TOTAL COMPREHENSIVE INCOME							1,211
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622

See Notes to Consolidated Financial Statements.

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

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 294	$ 490
Other Temporary Investments		
(December 31, 2010 amount includes $287 related to Transition Funding and EIS)	416	363
Accounts Receivable:		
Customers	683	492
Accrued Unbilled Revenues	195	503
Pledged Accounts Receivable - AEP Credit	949	-
Miscellaneous	137	92
Allowance for Uncollectible Accounts	(41)	(37)
Total Accounts Receivable	1,923	1,050
Fuel	837	1,075
Materials and Supplies	611	586
Risk Management Assets	232	260
Accrued Tax Benefits	389	547
Regulatory Asset for Under-Recovered Fuel Costs	81	85
Margin Deposits	88	89
Prepayments and Other Current Assets	145	211
TOTAL CURRENT ASSETS	5,016	4,756
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,352	23,045
Transmission	8,576	8,315
Distribution	14,208	13,549
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,846	3,744
Construction Work in Progress	2,758	3,031
Total Property, Plant and Equipment	53,740	51,684
Accumulated Depreciation and Amortization	18,066	17,340
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	35,674	34,344
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,943	4,595
Securitized Transition Assets	1,742	1,896
Spent Nuclear Fuel and Decommissioning Trusts	1,515	1,392
Goodwill	76	76
Long-term Risk Management Assets	410	343
Deferred Charges and Other Noncurrent Assets	1,079	946
TOTAL OTHER NONCURRENT ASSETS	9,765	9,248
TOTAL ASSETS	$ 50,455	$ 48,348

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2010 and 2009
(dollars in millions)

	2010	2009
CURRENT LIABILITIES		
Accounts Payable	$ 1,061	$ 1,158
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	690	-
Other Short-term Debt	656	126
Total Short-term Debt	1,346	126
Long-term Debt Due Within One Year	1,309	1,741
Risk Management Liabilities	129	120
Customer Deposits	273	256
Accrued Taxes	702	632
Accrued Interest	281	287
Regulatory Liability for Over-Recovered Fuel Costs	17	76
Deferred Gain and Accrued Litigation Costs	448	-
Other Current Liabilities	952	931
TOTAL CURRENT LIABILITIES	6,518	5,327
NONCURRENT LIABILITIES		
Long-term Debt		
(December 31, 2010 amount includes $1,857 related to Transition Funding, DCC Fuel and Sabine)	15,502	15,757
Long-term Risk Management Liabilities	141	128
Deferred Income Taxes	7,359	6,420
Regulatory Liabilities and Deferred Investment Tax Credits	3,171	2,909
Asset Retirement Obligations	1,394	1,254
Employee Benefits and Pension Obligations	1,893	2,189
Deferred Credits and Other Noncurrent Liabilities	795	1,163
TOTAL NONCURRENT LIABILITIES	30,255	29,820
TOTAL LIABILITIES	36,773	35,147
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	61
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2010	2009
Shares Authorized	600,000,000	600,000,000
Shares Issued	501,114,881	498,333,265

	2010	2009
(20,307,725 shares and 20,278,858 shares were held in treasury at December 31, 2010 and 2009, respectively)	3,257	3,239
Paid-in Capital	5,904	5,824
Retained Earnings	4,842	4,451
Accumulated Other Comprehensive Income (Loss)	(381)	(374)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,622	13,140
TOTAL EQUITY	13,622	13,140
TOTAL LIABILITIES AND EQUITY	$ 50,455	$ 48,348

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in millions)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 1,218	$ 1,365	$ 1,388
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,641	1,597	1,483
Deferred Income Taxes	809	1,244	498
Provision for SIA Refund	-	-	149
Discontinued Operations, Net of Tax	-	-	(12)
Extraordinary Loss, Net of Tax	-	5	-
Carrying Costs Income	(70)	(47)	(83)
Allowance for Equity Funds Used During Construction	(77)	(82)	(45)
Mark-to-Market of Risk Management Contracts	30	(59)	(140)
Amortization of Nuclear Fuel	139	63	88
Pension Contributions to Qualified Plan Trust	(500)	-	-
Property Taxes	(21)	(17)	(13)
Fuel Over/Under-Recovery, Net	(253)	(474)	(272)
Gains on Sales of Assets, Net	(14)	(15)	(17)
Change in Other Noncurrent Assets	(75)	(137)	(244)
Change in Other Noncurrent Liabilities	202	244	8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(866)	41	71
Fuel, Materials and Supplies	221	(475)	(183)
Margin Deposits	1	(3)	(40)
Accounts Payable	(36)	8	(94)
Customer Deposits	14	2	(48)
Accrued Taxes, Net	179	(470)	4
Accrued Interest	(8)	17	30
Other Current Assets	72	(70)	(29)
Other Current Liabilities	56	(262)	82
Net Cash Flows from Operating Activities	2,662	2,475	2,581
INVESTING ACTIVITIES			
Construction Expenditures	(2,345)	(2,792)	(3,800)
Change in Other Temporary Investments, Net	(4)	16	45
Purchases of Investment Securities	(1,918)	(853)	(1,922)
Sales of Investment Securities	1,817	748	1,917
Acquisitions of Nuclear Fuel	(91)	(169)	(192)
Acquisitions of Assets	(155)	(104)	(160)
Proceeds from Sales of Assets	187	278	90
Other Investing Activities	(14)	(40)	(5)
Net Cash Flows Used for Investing Activities	(2,523)	(2,916)	(4,027)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	93	1,728	159
Issuance of Long-term Debt	1,270	2,306	2,774
Commercial Paper and Credit Facility Borrowings	565	127	2,055
Change in Short-term Debt, Net	770	119	(660)
Retirement of Long-term Debt	(1,993)	(816)	(1,824)
Commercial Paper and Credit Facility Repayments	(115)	(2,096)	(79)
Principal Payments for Capital Lease Obligations	(95)	(82)	(97)
Dividends Paid on Common Stock	(824)	(758)	(666)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other Financing Activities	(3)	(5)	20
Net Cash Flows from (Used for) Financing Activities	(335)	520	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	(196)	79	233
Cash and Cash Equivalents at Beginning of Period	490	411	178
Cash and Cash Equivalents at End of Period	$ 294	$ 490	$ 411

See Notes to Consolidated Financial Statements.

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

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements and Extraordinary Item
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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with KGPCo and WPCo, provides only transmission and distribution services. TNC engages in the transmission and distribution of electric power and is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a nonutility affiliate. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated wind farms and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are cost-based due to PSO and SWEPCo having market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. They also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by REPs. Through its nonregulated subsidiaries, AEP enters into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. Effective November 2009, AEP had no active REPs in ERCOT. SWEPCo operates in the SPP area which includes a portion of Texas. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. CSPCo's and OPCo's retail transmission rates in Ohio and APCo's retail transmission rates in Virginia are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are the primary beneficiary of Sabine, DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, AEP Credit, Transition Funding and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLC as defined by the new accounting guidance for "Variable Interest Entities." In addition, we have not provided material financial or other support to Sabine, DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, Transition Funding, 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 years ended December 31, 2010, 2009 and 2008 were $133 million, $99 million and $110 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Consolidated Balance Sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2010, 2009 and 2008 were $35 million, $30 million and $28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. In December 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel III LLC. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC (collectively DCC Fuel) were 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. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and will begin in January 2011. Payments on the leases for the year ended December 31, 2010 were $59 million. No payments were made to DCC Fuel in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48, 54 and 54 month lease term, respectively. 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 leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our 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 Parent provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized 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 Consolidated Balance Sheets. See the "ASU 2009-17 'Consolidation' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010. Also, see "Securitized Accounts Receivables – AEP Credit" section of Note 14.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. Based on the shared control of DHLC's operations, management concluded as of January 1, 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC. SWEPCo's total billings from DHLC for the years ended December 31, 2010, 2009 and 2008 were $56 million, $43 million and $44 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on our Consolidated Balance Sheets at December 31, 2009 as well as our investment and maximum exposure as of December 31, 2010. As of January 1, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.8 billion at December 31, 2010 and are included in current and long-term debt on the Consolidated Balance Sheets. Transition Funding has securitized transition assets of $1.7 billion at December 31, 2010, which are presented separately on the face of the Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	Transition Funding
ASSETS					
Current Assets	$ 50	$ 92	$ 131	$ 924	$ 214
Net Property, Plant and Equipment	139	173	-	-	-
Other Noncurrent Assets	34	112	1	10	1,746
Total Assets	$ 223	$ 377	$ 132	$ 934	$ 1,960
LIABILITIES AND EQUITY					
Current Liabilities	$ 33	$ 79	$ 33	$ 886	$ 221
Noncurrent Liabilities	190	298	85	1	1,725
Equity	-	-	14	47	14
Total Liabilities and Equity	$ 223	$ 377	$ 132	$ 934	$ 1,960

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:

	December 31, 2010	
	As Reported on the Consolidated Balance Sheets	Maximum Exposure
	(in millions)	
Capital Contribution from SWEPCo	$ 6	$ 6
Retained Earnings	2	2
SWEPCo's Guarantee of Debt	-	48
Total Investment in DHLC	$ 8	$ 56

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP, and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. Neither the "Ohio Series" nor "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

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

Our investment in PATH-WV was:

	December 31,			
	2010		2009	
	As Reported on the Consolidated Balance Sheets	Maximum Exposure	As Reported on the Consolidated Balance Sheets	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 18	$ 18	$ 13	$ 13
Retained Earnings	6	6	3	3
Total Investment in PATH-WV	$ 24	$ 24	$ 16	$ 16

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Ohio for CSPCo and OPCo and in Texas for TNC. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

Accounting guidance for "Discontinuation of Rate-Regulated Operations" requires the recognition of an impairment of stranded net regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities. Such impairments and adjustments are classified as an extraordinary item. Consistent with accounting guidance for "Discontinuation of Rate-Regulated Operations," SWEPCo recorded an extraordinary reduction in earnings and shareholder's equity from the reapplication of "Regulated Operations" accounting guidance in 2009.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

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.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries. 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 Consolidated Balance Sheets (see "Securitized

Accounts Receivable – AEP Credit" section of Note 14). See "ASU 2009-16 'Transfers and Servicing' " section of Note 2 for a discussion of the impact of accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and are accounted for as financings.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Our nonregulated operations generally follow the policies of our cost-based rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and certain generating assets in Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest". We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

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 or 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 benefit plan and 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 plans.

Assets in the benefits and nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. 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. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

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		

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Texas, Louisiana and Arkansas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (prior to 2009) for APCo are reflected in rates in a timely manner through the FAC. Beginning in 2009, changes in fuel costs, including purchased power in Ohio for CSPCo and OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. All of the profits from off-system sales are given to customers through the FAC in West Virginia for APCo. A portion of profits from off-system sales are shared with customers through the FAC and other rate mechanisms in Oklahoma for PSO, Texas, Louisiana and Arkansas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent (prior to 2009 for CSPCo and OPCo in Ohio and currently in Texas for AEP Energy Partners, Inc.), changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our Consolidated Balance Sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on our Consolidated Statements of Income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on our Consolidated Statements of Income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and on adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, as well as over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Accounting for Cash Flow Hedging Strategies" section of Note 10).

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer distribution tree trimming costs for PSO above the level included in base rates and amortize those deferrals commensurate with recovery through a rate rider in Oklahoma.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Government Grants

In 2010, APCo received final approval for a federal stimulus grant for a commercial scale Carbon Capture and Sequestration facility under consideration at the Mountaineer Plant. Also in 2010, CSPCo received final approval for a federal stimulus grant for the gridSMART® demonstration program. For each project, APCo and CSPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. These reimbursements result in the reduction of Other Operation and Maintenance expenses on our Consolidated Statements of Income or a reduction in Construction Work in Progress on our Consolidated Balance Sheets.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently 10 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to targeted allocation when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimizing net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0 %	35.0 %	40.0 %
International and Global Equity	10.0 %	15.0 %	20.0 %
Fixed Income	35.0 %	39.0 %	45.0 %
Real Estate	4.0 %	5.0 %	6.0 %
Other Investments	1.0 %	5.0 %	7.0 %
Cash	0.5 %	1.0 %	3.0 %

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0 %	66.0 %	71.0 %
Fixed Income	29.0 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	4.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- Individual stock must be less than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added, and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with six general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

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.

We maintain trust records for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. 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.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. 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. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record 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 spent nuclear fuel disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on our Consolidated Balance Sheets in our equity section. Our components of AOCI as of December 31, 2010 and 2009 are shown in the following table:

	December 31,	
Components	**2010**	**2009**
	(in millions)	
Securities Available for Sale, Net of Tax	$ 4	$ 12
Cash Flow Hedges, Net of Tax	11	(15)
Amortization of Pension and OPEB Deferred Costs, Net of Tax	57	35
Pension and OPEB Funded Status, Net of Tax	(453)	(406)
Total	$ (381)	$ (374)

Stock-Based Compensation Plans

At December 31, 2010, we had stock options, performance units, restricted shares and restricted stock units outstanding under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2010, 2009 and 2008, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

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

Amounts Attributable to AEP Common Shareholders	2010	2009	2008
	Years Ended December 31, (in millions)		
Income Before Discontinued Operations and Extraordinary Loss	$ 1,211	$ 1,362	$ 1,368
Discontinued Operations, Net of Tax	-	-	12
Extraordinary Loss, Net of Tax	-	(5)	-
Net Income	$ 1,211	$ 1,357	$ 1,380

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 Consolidated Statements of Income:

	2010		2009		2008	
	Years Ended December 31, (in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,211		$ 1,357		$ 1,380	
Weighted Average Number of Basic Shares Outstanding	479.4	$ 2.53	458.7	$ 2.96	402.1	$ 3.43
Weighted Average Dilutive Effect of:						
Performance Share Units	0.1	-	0.3	-	1.2	0.01
Stock Options	-	-	-	-	0.1	-
Restricted Stock Units	0.1	-	-	-	0.1	-
Restricted Shares	-	-	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	479.6	$ 2.53	459.0	$ 2.96	403.6	$ 3.42

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

Options to purchase 136,250, 452,216 and 470,016 shares of common stock were outstanding at December 31, 2010, 2009 and 2008, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive.

CSPCo and OPCo Revised Depreciation Rates

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

	Depreciation Expense Variance
	Years Ended December 31, 2009/2008
	(in millions)
CSPCo	$ (18)
OPCo	71

The net change in depreciation rates resulted in a decrease to our net-of-tax, basic earnings per share of $0.08 for the year ended December 31, 2009.

Supplementary Information

Related Party Transactions	2010	2009	2008
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
Ohio Valley Electric Corporation (43.47% owned)	$ (20)(a)	$ -	$ (54)(b)
AEP Consolidated Revenues – Other Revenues:			
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	29	31	32
AEP Consolidated Expenses – Purchased Electricity for Resale:			
Ohio Valley Electric Corporation (43.47% Owned)	302 (c)	286	263

(a) The AEP Power Pool purchased power from OVEC to serve off-system sales in an agreement that began in January 2010 and ended in June 2010.
(b) The AEP Power Pool purchased power from OVEC as part of risk management activities in an agreement that ended in December 2008.
(c) The AEP Power Pool purchased power from OVEC to serve retail sales in an agreement that began in January 2010 and ended in June 2010. The total amount reported in 2010 includes $10 million related to this agreement.

Cash Flow Information	2010	2009	2008
		Years Ended December 31, (in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 958	$ 924	$ 853
Income Taxes	(268)	(98)	233
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	225	86	62
Assumption of Liabilities Related to Acquisitions	8	-	-
Government Grants Included in Accounts Receivable at December 31,	10	-	-
Construction Expenditures Included in Accounts Payable at December 31,	267	348	460
Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,	-	-	38
Noncash Donation Expense Related to Issuance of Treasury Shares to AEP Foundation	-	-	40

Transmission Investments

We participate in certain joint ventures which involve the development, construction, ownership and operation of transmission facilities. These investments are recorded using the equity method and reported as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets.

Adjustments to Securitized Accounts Receivable Disclosure

In the "Securitized Accounts Receivable – AEP Credit" section of Note 14, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or cash flows.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that impact our financial statements.

Pronouncements Adopted During 2010

The following standards were effective during 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 securitizes 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 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 and Transition Funding, wholly-owned consolidated subsidiaries. See "Variable Interest Entities" section of Note 1 for further discussion.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

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

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2010 and 2009 by operating segment are as follows:

	Utility Operations	AEP River Operations	AEP Consolidated
		(in millions)	
Balance at December 31, 2008	$ 37	$ 39	$ 76
Impairment Losses	-	-	-
Balance at December 31, 2009	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2010	$ 37	$ 39	$ 76

In the fourth quarters of 2010 and 2009, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $1.2 million and $10.3 million at December 31, 2010 and 2009, respectively, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2010		2009	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)			
Easements	10	$ 2.2	$ 2.2	$ 2.2	$ 1.9
Purchased Technology	10	10.9	9.7	10.9	8.6
Advanced Royalties	15	-	-	29.4	21.7
Total		$ 13.1	$ 11.9	$ 42.5	$ 32.2

Amortization of intangible assets was $1 million, $3 million and $3 million for 2010, 2009 and 2008, respectively. Our estimated total amortization is $1 million for 2011 and $138 thousand for 2012.

The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. As of January 1, 2010, SWEPCo no longer consolidates DHLC, but rather it is reported as an equity investment, resulting in the elimination of a review of this asset by SWEPCo. Also, see “ASU 2009-17 ‘Consolidations’” section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

Other than goodwill, we have no intangible assets that are not subject to amortization.

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESPs

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 limited 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 provided a FAC for the three-year period of the ESP. The FAC was phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the “2009 Fuel Adjustment Clause Audit” section below. The order allowed CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and accrued 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. 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 deferral as of December 31, 2010 was $476 million for OPCo excluding $30 million of unrecognized equity carrying costs.

Discussed below are the significant 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 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 gridSMART® 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 filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings under the Significantly Excessive Earnings Test (SEET). If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo's and OPCo's returns on common equity were 20.84% and 10.81%, respectively, including off-system sales margins. In January 2011, the PUCO issued an order that determined a return on common equity for 2009 in excess of 17.6% would be significantly excessive. The PUCO determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo earnings, excluding off-system sales margins, to be 19.73%, which exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered CSPCo to refund $43 million ($28 million net of tax) of its earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. The PUCO ordered that the significantly excessive earnings be applied first to CSPCo's FAC deferral, including unrecognized equity carrying costs, as of the date of the order, with any remaining balance to be credited to CSPCo's customers on a per kilowatt basis which began with the first billing cycle in February 2011 through December 2011. Several parties, including CSPCo and OPCo, have filed requests for rehearing with the PUCO, which remain pending. CSPCo and OPCo are required to file their 2010 SEET filing with the PUCO in 2011. Based upon the approach in the PUCO 2009 order, management does not currently believe that there are significantly excessive earnings in 2010.

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

Proposed January 2012 – May 2014 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing on a combined company basis for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The ESP also includes alternative energy resource requirements and addresses provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio and other matters. The SSO presents redesigned generation rates by customer class. Customer class rates individually vary, but on average, customers will experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC.

Requested Sporn Unit 5 Shutdown and Proposed Distribution Rider

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider, outside the rate caps established in the 2009 – 2011 ESP proceeding. The proposed rider would recover the net book value of the unit as well as related materials and supplies as of December 2010, which is estimated to be $59 million, as well as future closure costs incurred after December 2010. OPCo also requested authority to record the future closure costs as a regulatory asset or regulatory liability with a weighted average cost of capital carrying charge to be included in the proposed non-bypassable distribution rider after they are incurred. Also in October 2010, OPCo filed a retirement notification with PJM pending PUCO approval of OPCo's application to close Sporn Unit 5, which was granted by PJM. Pending PUCO approval, Sporn Unit 5 continues to operate. Management is unable to predict the outcome of this proceeding.

2009 Fuel Adjustment Clause Audit

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

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. The Industrial Energy Users-Ohio, CSPCo and OPCo filed Notices of Appeal regarding aspects of this decision with the Supreme Court of Ohio. A hearing at the Supreme Court of Ohio was held in February 2011. 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. These amounts exclude $1 million and $1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

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

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

As of December 31, 2010, CSPCo and OPCo have incurred $38 million and $30 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $35 million and $26 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $3 million and $4 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. The carrying costs include both a return of and on the environmental investments as well as related administrative and general expenses and taxes. In August 2010, the PUCO issued an order approving a rider of approximately $26 million and $34 million for CSPCo and OPCo, respectively, effective September 2010. The implementation of the rider will likely not impact cash flows since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings, but will increase the ESP phase-in plan deferrals associated with the FAC.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through December 31, 2010, CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

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

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $125 million for transmission, excluding AFUDC. As of December 31, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $1 billion of expenditures (including AFUDC and capitalized interest of $137 million and related transmission costs of $66 million). As of December 31, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $321 million (including related transmission costs of $3 million). SWEPCo's share of the contractual construction commitments is $235 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of December 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 significant outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

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's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club filed a complaint with the LPSC to begin an investigation into the construction of the Turk Plant. In November 2010, the LPSC dismissed the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. The parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas. In December 2010, the Circuit Court affirmed the APCEC. In January 2011, the same parties asked the Arkansas Court of Appeals to overturn the Circuit Court's December 2010 decision. A decision from the Arkansas Court of Appeals is pending.

A wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In 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, and sought a preliminary injunction to halt construction and for a temporary restraining order. In July 2010, the Hempstead County Hunting Club also filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of the Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The plaintiffs' federal law claims challenge the process used and terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. The plaintiffs' state law claims challenge SWEPCo's ability to construct the Turk Plant without obtaining a certificate from the APSC. In 2010, the motions for preliminary injunction were partially granted and upheld on appeal pending a hearing. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. A hearing on SWEPCo's appeal is scheduled for March 2011. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court accepted the request.

In January 2009, SWEPCo was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenors appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. The Arkansas Court of Appeals issued a decision in July 2010 remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines. In January 2011, the appellants filed requests to withdraw their appeals at the Court of Appeals and the APSC postponed a scheduled hearing pending a ruling on those requests. In February 2011, the Court of Appeals dismissed the appeals, and the APSC subsequently closed the remand docket, finding the CECPN decisions final and non-appealable. As previously discussed, the preliminary injunction issued by the Federal District Court related to the wetlands permit also impacts the uncompleted construction on portions of the transmission lines.

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

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of December 31, 2010, the Stall Unit cost applicable to the cap was $426 million, including $49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap. In July 2010, the Stall Unit was placed into Arkansas rates. SWEPCo received CWIP treatment for a portion of the Stall Unit in the 2009 Texas Base Rate Filing. See "2009 Texas Base Rate Filing" section below. The Stall Unit will be phased into Louisiana rates between October 2010 and October 2011.

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 common 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 common 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 decreased annual depreciation expense by $17 million and allowed SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from $3 million to $30 million in SWEPCo's $755 million fuel and purchased power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions.

In September 2010, the Administrative Law Judges issued a Proposal for Decision (PFD) that recommended a disallowance of a significant portion of the charges under a ten-year gas transportation agreement that began in 2009 for the Mattison Plant located in northwest Arkansas. In January 2011, the PUCT issued an order which overturned a portion of the PFD that recommended a finding of imprudence on the Mattison gas contract. The impact of this order had an immaterial impact on SWEPCo's financial statements.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision. An October 2010 decision of the Texas Supreme Court addressing the same issue for another utility upholds the Court of Appeals determination.

- 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 Retail Electric Providers (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 $22 million higher for the period July 2008 through December 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 $101 million as of December 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 Retail Electric Providers (REPs) excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded costs in the true-up proceeding.

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

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

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

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 common equity. Intervenors appealed the PUCT's decision but the Texas Court of Appeals affirmed the PUCT's decision in all material respects. The deadline to appeal this decision to the Texas Supreme Court has expired.

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

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a $62 million increase based on a 10.53% return on common equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility, which resulted in a pretax write-off of $54 million in Other Operation. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral of approximately $25 million of incremental storm expense incurred in 2009. Approximately $3 million, including interest, was refunded to customers in September 2010 related to the collection of interim rates.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. The filing also included a request for recovery of and a return on the West Virginia jurisdictional share of the Mountaineer Carbon Capture and Storage Product

Validation Facility. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. The settlement agreement allows APCo to defer and amortize up to $18 million of previously expensed 2009 incremental storm expenses over a period of eight years. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2 required the recording of an asset retirement obligation and an offsetting regulatory asset. As of December 31, 2010, APCo has recorded a noncurrent regulatory asset of $60 million related to the PVF.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the PVF costs. See "2009 Virginia Base Rate Case" section above.

In APCo's and WPCo's May 2010 West Virginia base rate filing, APCo and WPCo requested recovery of and a return on their West Virginia jurisdictional share of the project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. A decision from the WVPSC is expected in March 2011. If APCo cannot recover its remaining investment in and expenses related to the PVF, it would reduce future net income and cash flows and impact financial condition.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of December 31, 2010, APCo has incurred $14 million in total costs and has received $5 million of DOE funding resulting in a net $9 million balance included in Construction Work In Progress on the Consolidated Balance Sheets. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

In 2008, the Virginia SCC issued an order denying APCo's request for 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 common equity once the facility is placed into commercial operation. The order was based upon the Virginia SCC's 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 the 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 with the IGCC plant.

Through December 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 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 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 and lowered annual coal cost projections by $27 million.

In June 2010, the WVPSC approved a settlement agreement for $96 million, including $10 million of construction surcharges related to APCo's and WPCo's second year ENEC increase. The settlement agreement provided for recovery of the amounts related to the renegotiated coal contracts and allows APCo to accrue weighted average cost of capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. As of December 31, 2010, APCo's ENEC under-recovery balance was $361 million, excluding $3 million of unrecognized equity carrying costs, which is included in noncurrent regulatory assets. The new rates became effective in July 2010.

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) contended that PSO should not have collected the $42 million without specific OCC approval. In December 2010, the OCC issued orders which approved PSO's 2006 and prior fuel and purchased power costs without any adjustments.

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 prudence 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 decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions. Hearings are currently scheduled for March 2011. If the OCC were to issue an unfavorable decision, it could 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 common equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors appealed various issues but the Court of Civil Appeals affirmed the OCC's decision. No parties sought rehearing or appeal and, as a result, this case has concluded.

2010 Oklahoma Base Rate Case

In July 2010, PSO filed a request with the OCC to increase annual base rates by $82 million, including $30 million that is currently being recovered through a rider. The requested net annual increase to ratepayers would be $52 million. The requested increase included a $24 million increase in depreciation and an 11.5% return on common equity. In January 2011, the OCC approved a settlement agreement which did not change annual revenue or depreciation rates, but transferred $30 million into base rates that was previously being recovered through a capital investment rider. The order provided a 10.15% return on common equity and new rates were effective in February 2011.

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 6, Cook Plant Unit 1 (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 reduced 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 remaining 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. I&M maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

In October 2010, the Indiana/Michigan Industrial Group and the Indiana Office of Utility Consumer Counselor filed testimony which recommended I&M pay to customers a portion of the accidental outage insurance proceeds up to the extent not previously paid to customers through the fuel adjustment clause or needed to cover costs not covered by I&M's property damage insurance policy. In January 2011, a settlement agreement was filed with the IURC. The settlement stated (a) that I&M will credit an additional $14 million to customers through the fuel adjustment clause, (b) that the parties to the settlement will not oppose the need to replace the existing low-pressure turbine at Cook Unit 1, and (c) that the parties to the settlement agree that the cost of the replacement should not be offset by the accidental outage insurance proceeds received by I&M. In February 2011, the IURC approved the settlement agreement as filed.

Michigan 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 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. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation, which will be filed in March 2011. If any fuel clause revenues or accidental outage insurance proceeds have to be paid to customers, 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 6.

Michigan Base Rate Filing

In January 2010, I&M filed with the MPSC a request for a $63 million increase in annual base rates based on an 11.75% return on common equity. Starting with the August 2010 billing cycle, I&M, with MPSC authorization, implemented a $44 million interim rate increase. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In October 2010, a settlement agreement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity, effective December 2010, plus separate recovery of approximately $7 million of customer choice implementation costs over a two year period beginning April 2011. In addition, the approved revenue requirement includes the amortization of $6 million in previously expensed restructuring costs over five years, which I&M deferred in October 2010 and began amortizing in December 2010. Also, the approved settlement agreement provided for sharing of off-system sales margins between customers (75%) and I&M (25%) with customers receiving a credit in future Power Supply Cost Recovery proceedings for their jurisdictional share of any off-system sales margins. Through December 2010, I&M recorded a provision for refund of $3 million, including interest, related to interim rates that were in effect through November 2010. In January 2011, I&M filed an application with the MPSC requesting the MPSC find that $3 million, including interest, is the total amount to be refunded to customers. I&M is proposing to refund this amount to customers during April 2011. A decision from the MPSC is pending.

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 deferred storm restoration expenses over a three-year period. In June 2010, the KPSC approved a settlement agreement to increase base revenues by $64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of $23 million of deferred storm restoration expenses over five years. New rates became effective with the first billing cycle of July 2010.

FERC Rate Matters

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.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding 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 asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and required a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies 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 generally 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. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM/MISO Market Flow Calculation Settlement Adjustments

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 dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

5. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2010		December 31, 2009	Remaining Recovery Period
Current Regulatory Assets	(in millions)			
Under-recovered Fuel Costs - earns a return	$ 73		$ 85	1 year
Under-recovered Fuel Costs - does not earn a return	8		-	1 year
Total Current Regulatory Assets	$ 81		$ 85	
Noncurrent Regulatory Assets				
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	$ 59		$ 57	
Storm Related Costs - CSPCo, OPCo, TCC	55		49	
Line Extension Carrying Costs - CSPCo, OPCo	55		43	
Acquisition of Monongahela Power - CSPCo	8		10	
Other Regulatory Assets Not Yet Being Recovered	7		1	
Regulatory Assets Currently Not Earning a Return				
Mountaineer Carbon Capture and Storage Product Validation Facility - APCo	60		111	
Environmental Rate Adjustment Clause - APCo	56		25	
Storm Related Costs - APCo, KGPCo, PSO, SWEPCo	45		-	
Deferred Wind Power Costs - APCo	29		5	
Special Rate Mechanism for Century Aluminum - APCo	13		12	
Acquisition of Monongahela Power - CSPCo	4		-	
Transmission Rate Adjustment Clause - APCo	-	(a)	26	
Storm Related Costs - KPCo	-	(b)	24	
Other Regulatory Assets Not Yet Being Recovered	4		18	
Total Regulatory Assets Not Yet Being Recovered	395		381	
Regulatory assets being recovered:				
Regulatory Assets Currently Earning a Return				
Fuel Adjustment Clause - OPCo	476		341	2 to 8 years
Expanded Net Energy Charge - APCo	361	(c)	-	3 years
Unamortized Loss on Reacquired Debt	93		99	33 years
Storm Related Costs - PSO	38		53	3 years
RTO Formation/Integration Costs	21		23	9 years
Red Rock Generating Facility - PSO	10		11	46 years
Economic Development Rider - CSPCo, OPCo	1		12	1 year
Other Regulatory Assets Being Recovered	21		23	various
Regulatory Assets Currently Not Earning a Return				
Pension and OPEB Funded Status	2,161		2,139	13 years
Income Taxes, Net	1,097		966	37 years
Cook Nuclear Plant Refueling Outage Levelization - I&M	54		22	3 years
Postemployment Benefits	51		52	4 years
Storm Related Costs - KPCo	21	(b)	-	5 years
Transmission Rate Adjustment Clause - APCo	19	(a)	-	2 years
Asset Retirement Obligation - APCo, I&M	15		16	10 years
Restructuring Transition Costs - TCC	14		25	5 years
Off-system Sales Margin Sharing - I&M	13		18	1 year
Vegetation Management - PSO	13		16	1 year
Virginia Environmental and Reliability Costs Recovery - APCo	4		76	3 years
Expanded Net Energy Charge - APCo	-	(c)	282	
Other Regulatory Assets Being Recovered	65		40	various
Total Regulatory Assets Being Recovered	4,548		4,214	
Total Noncurrent Regulatory Assets	$ 4,943		$ 4,595	

(a) Recovery of regulatory asset through the transmission rate adjustment clause.
(b) Recovery of regulatory asset was granted during 2010.
(c) The majority of the balance results from the ENEC phase-in plan and earns a weighted average cost of capital carrying charge.

Regulatory liabilities are comprised of the following items:

	December 31, 2010	December 31, 2009	Remaining Refund Period
Current Regulatory Liability	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 16	$ 65	1 year
Over-recovered Fuel Costs - does not pay a return	1	11	1 year
Total Current Regulatory Liability	$ 17	$ 76	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Refundable Construction Financing Costs - SWEPCo	$ 20	$ -	
Other Regulatory Liabilities Not Yet Being Paid	-	3	
Regulatory Liabilities Currently Not Paying a Return			
Over-Recovery of gridSMART® Costs - CSPCo, PSO	10	9	
Other Regulatory Liabilities Not Yet Being Paid	11	10	
Total Regulatory Liabilities Not Yet Being Paid	41	22	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,222	2,048	(a)
Advanced Metering Infrastructure Surcharge - TCC, TNC	61	30	10 years
Deferred Investment Tax Credits	32	41	up to 12 years
Excess Earnings - SWEPCo, TNC	13	11	43 years
Transmission Cost Recovery Rider - CSPCo, OPCo	2	25	1 year
Other Regulatory Liabilities Being Paid	2	2	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability - I&M	354	281	(b)
Deferred Investment Tax Credits	242	239	up to 76 years
Unrealized Gain on Forward Commitments	60	74	5 years
Spent Nuclear Fuel Liability - I&M	42	41	(b)
Over-recovery of Transition Charges - TCC	38	38	9 years
Deferred State Income Tax Coal Credits - APCo	29	28	9 years
Over-recovery of PJM Expenses - I&M	12	18	1 year
Energy Efficiency/Peak Demand Reduction	10	2	2 years
Other Regulatory Liabilities Being Paid	11	9	various
Total Regulatory Liabilities Being Paid	3,130	2,887	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,171	$ 2,909	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

6. 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.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. We forecast approximately $2.5 billion and $2.6 billion of construction expenditures excluding AFUDC and capitalized interest for 2011 and 2012, respectively. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments at December 31, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,810	$ 3,974	$ 2,543	$ 3,718	$ 13,045
Energy and Capacity Purchase Contracts (b)	69	199	204	1,101	1,573
Total	$ 2,879	$ 4,173	$ 2,747	$ 4,819	$ 14,618

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

(b) Represents contractual commitments for energy and capacity purchase contracts.

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 with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two $1.5 billion credit facilities, of which $750 million may be issued under one credit facility as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013 and allows for the issuance of up to $600 million as letters of credit. As of December 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million with maturities ranging from January 2011 to November 2011.

In June 2010, we reduced a $627 million credit agreement to $478 million. As of December 31, 2010, $477 million of letters of credit with maturities ranging from March 2011 to April 2011 were issued by subsidiaries under this 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 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 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2010, SWEPCo has collected approximately $49 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $25 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $22 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the "Dispositions" section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price. This maximum exposure of approximately $1 billion relates to the Bank of America (BOA) litigation indemnity pertaining to the sale of Houston Pipeline Company in 2005 (see "Enron Bankruptcy" section of this note), of which $448 million is recorded in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Consolidated Balance Sheet as of December 31, 2010. In February 2011, all matters related to the BOA litigation were resolved and we paid BOA $425 million. There are no material amounts recorded for any indemnifications other than the deferred gain (plus interest and attorneys' fees) related to the BOA litigation which settled in February 2011.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of lease residual value guarantees.

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 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 two liability trials, the jury found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. In October 2010, the Seventh Circuit dismissed all remaining claims in these cases. Beckjord is operated by Duke Energy Ohio, Inc.

SWEPCo Citizen Suit and Notice of Violation

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 the 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, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects 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 similar to the claims made in the citizen suit. 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 the citizen suit and has taken no further action. We are unable to predict the timing of any future action by the Federal EPA. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The 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 CO_2 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 CO_2 emissions or that the Federal EPA could regulate CO_2 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. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. We believe the actions are without merit and intend to continue to defend against the claims.

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 CO_2 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. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. 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. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2010, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at four sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ and recorded a provision of approximately $11 million. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

Amos Plant – State and Federal Enforcement Proceedings

In March 2010, we received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with particulate matter emission limits) that lasted for more than thirty consecutive minutes in a 24-hour period and that certain required notifications were not made. We met with representatives of DAQ to discuss these occurrences and the steps we have taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. We have denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. We continue to discuss the resolution of these issues with DAQ, but cannot predict the outcome of these discussions or the amount of any penalty that may be assessed.

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 provided additional information to 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 retrofits on two Cardinal Plant units and a Conesville Plant unit are operational. Due to unexpected operating results, we completed an extensive review in 2009 of the design and manufacture of the JBR internal components. Our review concluded that there were 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. In 2010, we settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

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 liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $14 million in 2010, $16 million in 2009 and $27 million in 2008. Reduced annual decommissioning cost recovery amounts reflect the units' longer estimated life and operating licenses granted by the NRC. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2010 and 2009, the total decommissioning trust fund balance was $1.2 billion and $1.1 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2010 and 2009, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $307 million and $306 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.

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 December 31, 2010, we recorded $46 million in Prepayments and Other Current Assets on our Consolidated Balance Sheets representing estimated recoverable amounts under the property insurance policy. Through December 31, 2010, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the 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 review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. The treatment of the remaining accidental outage policy revenues through fuel clauses is discussed in "I&M Rate Matters" section of Note 4. 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

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on our net income, cash flows and financial condition.

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease, but no agreement was reached prior to the end of the lease.

I&M and Fort Wayne reached a settlement agreement. The agreement, signed in October 2010, is subject to approval by the IURC. I&M filed a petition with the IURC seeking approval. If the agreement is approved, I&M will purchase the remaining leased property and settle claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, inclusive of interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. I&M will seek recovery in rates of the payments made to Fort Wayne. If the agreement is not approved by the IURC, the parties have the right to terminate the agreement and pursue other relief.

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 was being litigated in federal courts in Texas and New York.

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 New York court entered a final judgment of $346 million. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. In October 2010, the Court of Appeals affirmed the New York district court's decision as to the final judgment of $346 million plus interest and reversed the New York district court decision as to the judgment dismissing our claims against BOA in the Southern District of Texas.

In 2005, we sold our interest in HPL and 30 BCF of working gas for approximately $1 billion. Although the assets were legally transferred, we were unable to determine all costs associated with the transfer until the BOA litigation was resolved. We indemnified the buyer of HPL against any damages up to the purchase price resulting from the BOA litigation, including the right to use the 55 BCF of natural gas through 2031. As a result, we deferred the entire gain related to the sale of HPL (approximately $380 million) pending resolution of the Enron and BOA disputes.

The deferred gain related to the sale of HPL, plus accrued interest and attorneys' fees related to the New York court's judgment was $448 million at December 31, 2010 and is included in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Consolidated Balance Sheet. $441 million related to this matter was included in Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheet at December 31, 2009. The effect of this decision had no impact on consolidated net income for 2010.

In February 2011, we reached a settlement with BOA covering claims in both the New York and Texas proceedings and paid BOA $425 million. The settlement covers all claims with BOA and Enron. We received title to the 55 BCF of natural gas in the Bammel storage facility as part of the settlement. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

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 remaining exposure is immaterial.

7. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

2010

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). In October 2010, SWEPCo finalized the purchase for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

2009

Oxbow Lignite Company and Red River Mining Company (Utility Operations segment)

On December 29, 2009, SWEPCo purchased 50% of the Oxbow Lignite Company, LLC (OLC) membership interest for $13 million. CLECO acquired the remaining 50% membership interest in the OLC for $13 million. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and CLECO's jointly-owned Dolet Hills Generating Station. SWEPCo will account for OLC as an equity investment. Also, on December 29, 2009, DHLC purchased mining equipment and assets for $16 million from the Red River Mining Company.

2008

Erlbacher companies (AEP River Operations segment)

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

DISPOSITIONS

2010

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

TCC and TNC sold, at cost, $66 million and $73 million, respectively, of transmission facilities to ETT for the year ended December 31, 2010.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain ($10 million, net of tax). We recorded the gain in Interest and Investment Income on our Consolidated Statements of Income for the year ended December 31, 2010.

2009

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

In 2009, TCC and TNC sold, at cost, $93 million and $2 million, respectively, of transmission facilities to ETT.

2008

None

DISCONTINUED OPERATIONS

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify those businesses or activities as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were discontinued in 2008. Results of operations of these businesses are classified as shown in the following table:

	U.K. Generation (a) (in millions)
2010 Revenue	$ -
2010 Pretax Income	-
2010 Earnings, Net of Tax	-
2009 Revenue	$ -
2009 Pretax Income	-
2009 Earnings, Net of Tax	-
2008 Revenue	$ 2
2008 Pretax Income	2
2008 Earnings, Net of Tax	12

(a) The 2008 amounts relate primarily to favorable income tax reserve adjustments.

8. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide medical and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of our benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Rate of Compensation Increase	4.95 % (a)	4.60 % (a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A Not applicable

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.95%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of our benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Discount Rate	5.60 %	6.00 %	6.00 %	5.85 %	6.10 %	6.20 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	8.00 %	7.75 %	8.00 %
Rate of Compensation Increase	4.60 %	5.90 %	5.90 %	N/A	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2010	2009
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	255	(209)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. We monitor the plans to control security diversification and ensure compliance with our investment policy. At December 31, 2010, the assets were invested in compliance with all investment limits. See “Investments Held in Trust for Future Liabilities” section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2010	**2009**	**2010**	**2009**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation at January 1	$ 4,701	$ 4,301	$ 1,941	$ 1,843
Service Cost	111	104	47	42
Interest Cost	253	254	113	110
Actuarial Loss	222	290	164	32
Plan Amendment Prior Service Credit	-	-	(36)	-
Benefit Payments	(480)	(248)	(142)	(120)
Participant Contributions	-	-	29	25
Medicare Subsidy	-	-	9	9
Benefit Obligation at December 31	$ 4,807	$ 4,701	$ 2,125	$ 1,941
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,403	$ 3,161	$ 1,308	$ 1,018
Actual Gain on Plan Assets	420	482	149	235
Company Contributions	515	8	117	150
Participant Contributions	-	-	29	25
Benefit Payments	(480)	(248)	(142)	(120)
Fair Value of Plan Assets at December 31	$ 3,858	$ 3,403	$ 1,461	$ 1,308
Underfunded Status at December 31	$ (949)	$ (1,298)	$ (664)	$ (633)

Benefit Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	**2009**	**2010**	**2009**
	(in millions)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (8)	$ (10)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(941)	(1,288)	(660)	(629)
Underfunded Status	$ (949)	$ (1,298)	$ (664)	$ (633)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in millions)			
Net Actuarial Loss	$ 2,129	$ 2,096	$ 638	$ 546
Prior Service Cost (Credit)	11	12	(20)	3
Transition Obligation	-	-	3	43
Recorded as				
Regulatory Assets	$ 1,764	$ 1,750	$ 388	$ 380
Deferred Income Taxes	132	125	81	74
Net of Tax AOCI	244	233	152	138

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2010	2009	2010	2009
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 121	$ 130	$ 121	$ (127)
Prior Service Credit	-	-	(36)	-
Amortization of Actuarial Loss	(89)	(59)	(29)	(42)
Amortization of Transition Obligation	-	-	(27)	(27)
Change for the Year	$ 32	$ 71	$ 29	$ (196)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,350	$ 2	$ -	$ -	$ 1,352	35.1 %
International	403	-	-	-	403	10.4 %
Real Estate Investment Trusts	112	-	-	-	112	2.9 %
Common Collective Trust - International	-	163	-	-	163	4.2 %
Subtotal - Equities	1,865	165	-	-	2,030	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	634	-	-	634	16.4 %
Corporate Debt	-	672	-	-	672	17.4 %
Foreign Debt	-	127	-	-	127	3.3 %
State and Local Government	-	23	-	-	23	0.6 %
Other - Asset Backed	-	51	-	-	51	1.3 %
Subtotal - Fixed Income	-	1,507	-	-	1,507	39.0 %
Real Estate	-	-	83	-	83	2.2 %
Alternative Investments	-	-	130	-	130	3.4 %
Securities Lending	-	254	-	-	254	6.6 %
Securities Lending Collateral (a)	-	-	-	(276)	(276)	(7.1)%
Cash and Cash Equivalents (b)	-	127	-	2	129	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	1	1	- %
Total	$ 1,865	$ 2,053	$ 213	$ (273)	$ 3,858	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for AEP's pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in millions)	
Balance as of January 1, 2010	$ 90	$ 106	$ 196
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(7)	4	(3)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	19	19
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 83	$ 130	$ 213

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 584	$ -	$ -	$ -	$ 584	40.0 %
International	220	-	-	-	220	15.1 %
Common Collective Trust - Global	-	115	-	-	115	7.9 %
Subtotal - Equities	804	115	-	-	919	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	48	-	-	48	3.3 %
United States Government and Agency Securities	-	93	-	-	93	6.4 %
Corporate Debt	-	110	-	-	110	7.5 %
Foreign Debt	-	25	-	-	25	1.7 %
State and Local Government	-	3	-	-	3	0.2 %
Other - Asset Backed	-	1	-	-	1	0.1 %
Subtotal - Fixed Income	-	280	-	-	280	19.2 %
Trust Owned Life Insurance:						
International Equities	-	49	-	-	49	3.3 %
United States Bonds	-	163	-	-	163	11.1 %
Cash and Cash Equivalents (a)	21	25	-	1	47	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	3	3	0.2 %
Total	$ 825	$ 632	$ -	$ 4	$ 1,461	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 1,219	$ -	$ -	$ -	$ 1,219	35.8 %
International	320	-	-	-	320	9.4 %
Real Estate Investment Trusts	87	-	-	-	87	2.6 %
Common Collective Trust - International	-	161	-	-	161	4.7 %
Subtotal - Equities	1,626	161	-	-	1,787	52.5 %
Fixed Income:						
United States Government and Agency Securities	-	233	-	-	233	6.9 %
Corporate Debt	-	831	-	-	831	24.4 %
Foreign Debt	-	171	-	-	171	5.0 %
State and Local Government	-	35	-	-	35	1.0 %
Other - Asset Backed	-	27	-	-	27	0.8 %
Subtotal - Fixed Income	-	1,297	-	-	1,297	38.1 %
Real Estate	-	-	90	-	90	2.7 %
Alternative Investments	-	-	106	-	106	3.1 %
Securities Lending	-	173	-	-	173	5.1 %
Securities Lending Collateral (a)	-	-	-	(196)	(196)	(5.8)%
Cash and Cash Equivalents (b)	-	116	-	4	120	3.5 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	26	26	0.8 %
Total	$ 1,626	$ 1,747	$ 196	$ (166)	$ 3,403	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments (in millions)	Total Level 3
Balance as of January 1, 2009	$ 137	$ 106	$ 243
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(47)	(14)	(61)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	13	13
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 90	$ 106	$ 196

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 343	$ -	$ -	$ -	$ 343	26.2 %
International	375	-	-	-	375	28.7 %
Common Collective Trust - Global	-	93	-	-	93	7.1 %
Subtotal - Equities	718	93	-	-	811	62.0 %
Fixed Income:						
Common Collective Trust - Debt	-	38	-	-	38	2.9 %
United States Government and Agency Securities	-	42	-	-	42	3.2 %
Corporate Debt	-	141	-	-	141	10.8 %
Foreign Debt	-	32	-	-	32	2.4 %
State and Local Government	-	6	-	-	6	0.5 %
Other - Asset Backed	-	2	-	-	2	0.2 %
Subtotal - Fixed Income	-	261	-	-	261	20.0 %
Trust Owned Life Insurance:						
International Equities	-	75	-	-	75	5.7 %
United States Bonds	-	131	-	-	131	10.0 %
Cash and Cash Equivalents (a)	7	14	-	1	22	1.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	8	8	0.6 %
Total	$ 725	$ 574	$ -	$ 9	$ 1,308	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation	December 31, 2010	2009
	(in millions)	
Qualified Pension Plan	$ 4,659	$ 4,539
Nonqualified Pension Plans	80	90
Total	$ 4,739	$ 4,629

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2010 and 2009 were as follows:

	Underfunded Pension Plans December 31, 2010	Underfunded Pension Plans December 31, 2009
	(in millions)	
Projected Benefit Obligation	$ 4,807	$ 4,701
Accumulated Benefit Obligation	$ 4,739	$ 4,629
Fair Value of Plan Assets	3,858	3,403
Underfunded Accumulated Benefit Obligation	$ (881)	$ (1,226)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $158 million and the OPEB plans of $86 million during 2011. The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by ERISA plus payment of unfunded nonqualified benefits. For the qualified pension plan, we may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2011	$ 314	$ 143	$ 11
2012	320	148	12
2013	325	153	13
2014	333	160	14
2015	342	166	15
Years 2016 to 2020, in Total	1,811	931	95

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2010, 2009 and 2008:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	(in millions)					
Service Cost	$ 111	$ 104	$ 100	$ 47	$ 42	$ 42
Interest Cost	253	254	249	113	110	113
Expected Return on Plan Assets	(312)	(321)	(336)	(105)	(80)	(111)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost	-	-	1	-	-	-
Amortization of Net Actuarial Loss	89	59	37	29	42	9
Net Periodic Benefit Cost	141	96	51	111	141	80
Capitalized Portion	(44)	(30)	(16)	(35)	(44)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 97	$ 66	$ 35	$ 76	$ 97	$ 55

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2011 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 121	$ 33
Prior Service Cost (Credit)	1	(2)
Transition Obligation	-	2
Total Estimated 2011 Amortization	$ 122	$ 33
Expected to be Recorded as		
Regulatory Asset	$ 99	$ 19
Deferred Income Taxes	8	5
Net of Tax AOCI	15	9
Total	$ 122	$ 33

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. We provided matching contributions of 75% of the first 6% of eligible compensation contributed by an employee in 2008. Effective January 1, 2009, we match the first 1% of eligible employee contributions at 100% and the next 5% of contributions at 70%. The cost for company matching contributions totaled $61 million in 2010, $74 million in 2009 and $71 million in 2008.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions and benefits paid were not material in 2010, 2009 and 2008.

9. BUSINESS SEGMENTS

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 and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Utility Operations

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

AEP River Operations

- Commercial barging operations that annually transport approximately 39 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 46% of the barging is for transportation of agricultural products, 25% for coal, 11% for steel and 18% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT and to a lesser extent Ohio in PJM and MISO.

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.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- 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 settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for years ended December 31, 2010, 2009 and 2008 and balance sheet information as of December 31, 2010 and 2009. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2010						
Revenues from:						
External Customers	$ 13,687	$ 566	$ 173	$ 1	$ -	$ 14,427
Other Operating Segments	104	22	-	14	(140)	-
Total Revenues	$ 13,791	$ 588	$ 173	$ 15	$ (140)	$ 14,427
Depreciation and Amortization	$ 1,598	$ 24	$ 30	$ 2	$ (13)(b)	$ 1,641
Interest Income	8	-	2	31	(20)	21
Interest Expense	942	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	650	19	(20)	(6)	-	643
Net Income (Loss)	1,201	37	25	(45)	-	1,218
Gross Property Additions	2,475	23	1	1	-	2,500

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2009						
Revenues from:						
External Customers	$ 12,733 (e)	$ 490	$ 281	$ (15)	$ -	$ 13,489
Other Operating Segments	70 (e)	18	5	36	(129)	-
Total Revenues	$ 12,803	$ 508	$ 286	$ 21	$ (129)	$ 13,489
Depreciation and Amortization	$ 1,561	$ 17	$ 29	$ 2	$ (12)(b)	$ 1,597
Interest Income	4	-	-	47	(40)	11
Interest Expense	916	5	21	86	(55)(b)	973
Income Tax Expense (Credit)	553	23	-	(1)	-	575
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 1,329	$ 47	$ 41	$ (47)	$ -	$ 1,370
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	$ 1,324	$ 47	$ 41	$ (47)	$ -	$ 1,365
Gross Property Additions	$ 2,813	$ 81	$ 1	$ 1	$ -	$ 2,896

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2008						
Revenues from:						
External Customers	$ 13,326 (e)	$ 616	$ 485	$ 13	$ -	$ 14,440
Other Operating Segments	240 (e)	30	(122)	9	(157)	-
Total Revenues	$ 13,566	$ 646	$ 363	$ 22	$ (157)	$ 14,440
Depreciation and Amortization	$ 1,450	$ 14	$ 28	$ 2	$ (11)(b)	$ 1,483
Interest Income	42	-	1	78	(65)	56
Interest Expense	915	5	22	94	(79)(b)	957
Income Tax Expense	515	26	17	84	-	642
Income Before Discontinued Operations and Extraordinary Loss	$ 1,123	$ 55	$ 65	$ 133	$ -	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	12	-	12
Net Income	$ 1,123	$ 55	$ 65	$ 145	$ -	$ 1,388
Gross Property Additions	$ 3,871	$ 116	$ 2	$ (29)(c)	$ -	$ 3,960

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
December 31, 2010						
Total Property, Plant and Equipment	$ 52,822	$ 574	$ 584	$ 11	$ (251)	$ 53,740
Accumulated Depreciation and Amortization	17,795	110	198	9	(46)	18,066
Total Property, Plant and Equipment - Net	$ 35,027	$ 464	$ 386	$ 2	$ (205)	$ 35,674
Total Assets	$ 48,780	$ 621	$ 881	$ 15,942	$ (15,769) (d)	$ 50,455
Investments in Equity Method Investees	157	3	-	-	-	160

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
December 31, 2009						
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) (d)	$ 48,348
Investments in Equity Method Investees	84	4	-	-	-	88

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- 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 settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

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

(c) Gross Property Additions for All Other includes construction expenditures of $8 million in 2008 related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines were refurbished and transferred to a generating facility within our Utility Operations segment in the fourth quarter of 2008. The transfer of these turbines resulted in the elimination of $37 million from All Other and the addition of $37 million to Utility Operations.

(d) 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.

(e) 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 was 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 and $122 million for the years ended December 31, 2009 and 2008, respectively. The Generation and Marketing segment also reported these purchase 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.

10. 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

Trading Strategies

Our strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact.

Risk Management Strategies

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value 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 power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as “Interest Rate and Foreign Currency.” The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

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

Notional Volume of Derivative Instruments

	Volume				
	December 31,				Unit of
	2010		2009		Measure
	(in millions)				
Commodity:					
Power		652		589	MWHs
Coal		63		60	Tons
Natural Gas		94		127	MMBtus
Heating Oil and Gasoline		6		6	Gallons
Interest Rate	$	171	$	216	USD
Interest Rate and Foreign Currency	$	907	$	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 power, coal, natural gas and heating oil and gasoline ("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 heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." We do not hedge all fuel price risk.

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 December 31, 2010 and 2009 balance sheets, we netted $8 million and $12 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $109 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 Consolidated Balance Sheets as of December 31, 2010 and 2009:

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)(c)**	**Other (a) (b)**	**Total**
		(in millions)			
Current Risk Management Assets	$ 1,023	$ 18	$ 30	$ (839)	$ 232
Long-term Risk Management Assets	546	12	2	(150)	410
Total Assets	1,569	30	32	(989)	642
Current Risk Management Liabilities	995	13	2	(881)	129
Long-term Risk Management Liabilities	387	6	3	(255)	141
Total Liabilities	1,382	19	5	(1,136)	270
Total MTM Derivative Contract Net Assets (Liabilities)	$ 187	$ 11	$ 27	$ 147	$ 372

Fair Value of Derivative Instruments
December 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (a) (b)**	**Total**
		(in millions)			
Current Risk Management Assets	$ 1,078	$ 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 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.

(c) At December 31, 2010, Risk Management Assets included $7 million and Risk Management Liabilities included $1 million related to fair value hedging strategies while the remainder related to cash flow hedging strategies. At December 31, 2009, we only employed cash flow hedging strategies.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	**Years Ended December 31, 2010**	**2009**
	(in millions)	
Utility Operations Revenue	$ 85	$ 144
Other Revenue	9	19
Regulatory Assets (a)	(9)	(28)
Regulatory Liabilities (a)	38	(7)
Total Gain (Loss) on Risk Management Contracts	$ 123	$ 128

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on 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 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 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 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 and unrealized 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 Consolidated Statements of Income. During 2010, we recognized gains of $6 million on our hedging instruments, offsetting losses of $6 million on our long-term debt and an immaterial amount of hedge ineffectiveness. During 2009, we did not employ any fair value hedging strategies. During 2008, we employed fair value hedging strategies and recognized an immaterial loss and no hedge ineffectiveness.

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 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 power, coal, natural gas, and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During 2010, 2009 and 2008, 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 Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Consolidated Statements of Income. During 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 2010, 2009 and 2008, 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 Consolidated Balance Sheets into Depreciation and Amortization expense on our Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2010, 2009 and 2008, we designated foreign currency derivatives as cash flow hedges.

During 2009, we recognized a $6 million gain in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2010, 2009 and 2008, hedge ineffectiveness was immaterial or nonexistent for all of the other hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the years ended December 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
Year Ended December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	9	13	22
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	-	-	-
Other Revenue	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Interest Expense	-	4	4
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2008	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(6)	11	5
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(15)	-	(15)
Other Revenue	(15)	-	(15)
Purchased Electricity for Resale	29	-	29
Interest Expense	-	5	5
Regulatory Assets (a)	5	-	5
Regulatory Liabilities (a)	(7)	-	(7)
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

During 2008 we reclassified $7 million of gains from AOCI to net income.

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

Impact of Cash Flow Hedges on our Consolidated Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 13	$ 25	$ 38
Hedging Liabilities (a)	(2)	(4)	(6)
AOCI Gain (Loss) Net of Tax	7	4	11
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(2)	1

Impact of Cash Flow Hedges on our 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 Gain (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 Consolidated Balance Sheets.

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 December 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 41 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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 the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, we are obligated to post an additional 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 do not anticipate a downgrade below investment grade. The following table represents: (a) our aggregate fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 20	$ 10
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	45	34
Amount Attributable to RTO and ISO Activities	44	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 outstanding 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 do not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 401	$ 567
Amount of Cash Collateral Posted	81	15
Additional Settlement Liability if Cross Default Provision is Triggered	213	199

11. FAIR VALUE MEASUREMENTS

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 December 31, 2010 and 2009 are summarized in the following table:

	December 31, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 16,811	$ 18,285	$ 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. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2010			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 225	$ -	$ -	$ 225
Fixed Income Securities:				
Mutual Funds	69	-	-	69
Variable Rate Demand Notes	97	-	-	97
Equity Securities - Mutual Funds	18	7	-	25
Total Other Temporary Investments	$ 409	$ 7	$ -	$ 416

	December 31, 2009			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 223	$ -	$ -	$ 223
Fixed Income Securities:				
Mutual Funds	57	-	-	57
Variable Rate Demand Notes	45	-	-	45
Equity Securities:				
Domestic	1	15	-	16
Mutual Funds	18	4	-	22
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 years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in millions)	
Proceeds From Investment Sales	$ 455	$ 35	$ 1,185
Purchases of Investments	503	82	1,118
Gross Realized Gains on Investment Sales	16	-	-
Gross Realized Losses on Investment Sales	-	-	-

At December 31, 2010 and 2009, we had no Other Temporary Investments with an unrealized loss position. In June 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell captive insurance company. At December 31, 2010, the fair value of fixed income securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes. Mutual funds may be sold and do not contain maturity dates.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

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

	December 31,					
	2010			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	$ 20	$ -	$ -	$ 14	$ -	$ -
Fixed Income Securities:						
United States Government	461	23	(1)	401	13	(4)
Corporate Debt	59	4	(2)	57	5	(2)
State and Local Government	341	(1)	-	369	8	1
Subtotal Fixed Income Securities	861	26	(3)	827	26	(5)
Equity Securities - Domestic	634	183	(123)	551	234	(119)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,515	$ 209	$ (126)	$ 1,392	$ 260	$ (124)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
	(in millions)		
Proceeds From Investment Sales	$ 1,362	$ 713	$ 732
Purchases of Investments	1,415	771	804
Gross Realized Gains on Investment Sales	12	28	33
Gross Realized Losses on Investment Sales	2	1	7

The adjusted cost of debt securities was $835 million and $801 million as of December 31, 2010 and 2009, respectively.

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

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 22
1 year – 5 years	306
5 years – 10 years	257
After 10 years	276
Total	$ 861

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

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 December 31, 2010 and 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
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 170	$ -	$ -	$ 124	$ 294
Other Temporary Investments					
Restricted Cash (a)	184	-	-	41	225
Fixed Income Securities:					
Mutual Funds	69	-	-	-	69
Variable Rate Demand Notes	-	97	-	-	97
Equity Securities - Mutual Funds (b)	25	-	-	-	25
Total Other Temporary Investments	278	97	-	41	416
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	20	1,432	112	(1,013)	551
Cash Flow Hedges:					
Commodity Hedges (c)	11	17	-	(15)	13
Fair Value Hedges	-	7	-	-	7
Interest Rate/Foreign Currency Hedges	-	25	-	-	25
Dedesignated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	31	1,481	112	(982)	642
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	8	-	12	20
Fixed Income Securities:					
United States Government	-	461	-	-	461
Corporate Debt	-	59	-	-	59
State and Local Government	-	341	-	-	341
Subtotal Fixed Income Securities	-	861	-	-	861
Equity Securities - Domestic (b)	634	-	-	-	634
Total Spent Nuclear Fuel and Decommissioning Trusts	634	869	-	12	1,515
Total Assets	$ 1,113	$ 2,447	$ 112	$ (805)	$ 2,867
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 25	$ 1,325	$ 27	$ (1,114)	$ 263
Cash Flow Hedges:					
Commodity Hedges (c)	4	13	-	(15)	2
Fair Value Hedges	-	1	-	-	1
Interest Rate/Foreign Currency Hedges	-	4	-	-	4
Total Risk Management Liabilities	$ 29	$ 1,343	$ 27	$ (1,129)	$ 270

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 427	$ -	$ -	$ 63	$ 490
Other Temporary Investments					
Restricted Cash (a)	198	-	-	25	223
Fixed Income Securities:					
Mutual Funds	57	-	-	-	57
Variable Rate Demand Notes	-	45	-	-	45
Equity Securities (b):					
Domestic	16	-	-	-	16
Mutual Funds	22	-	-	-	22
Total Other Temporary Investments	293	45	-	25	363
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	8	1,609	72	(1,119)	570
Cash Flow Hedges:					
Commodity Hedges (c)	1	11	-	(4)	8
Dedesignated Risk Management Contracts (d)	-	-	-	25	25
Total Risk Management Assets	9	1,620	72	(1,098)	603
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	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 - Domestic (b)	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 Commodity Contracts (c) (g)	$ 11	$ 1,415	$ 10	$ (1,205)	$ 231
Cash Flow Hedges:					
Commodity Hedges (c)	-	16	-	(4)	12
Interest Rate/Foreign Currency Hedges	-	5	-	-	5
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 publicly traded equity securities and equity-based mutual funds.
(c) 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."
(d) 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.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(f) The December 31, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($2) million in 2011, $2 million in periods 2012-2014 and ($5) million in periods 2015-2018; Level 2 matures $13 million in 2011, $66 million in periods 2012-2014, $12 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $18 million in 2011, $24 million in periods 2012-2014, $16 million in periods 2015-2016 and $27 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.
(g) 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 year ended December 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:

Year Ended December 31, 2010	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2009	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	63
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(25)
Transfers into Level 3 (d) (h)	18
Transfers out of Level 3 (e) (h)	(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2010	$ 85

Year Ended December 31, 2009	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2008	$ 49
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	44
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(17)
Transfers in and/or out of Level 3 (f)	(25)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2009	$ 62

Year Ended December 31, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of December 31, 2007	$ 49	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	-	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)			
Relating to Assets Still Held at the Reporting Date (a)	12	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (c)	-	(118)	(17)
Transfers in and/or out of Level 3 (f)	(36)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	24	-	-
Balance as of December 31, 2008	$ 49	$ -	$ -

(a) Included in revenues on our 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 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.

12. INCOME TAXES

The details of our consolidated income taxes before discontinued operations and extraordinary loss as reported are as follows:

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Federal:			
Current	$ (134)	$ (575)	$ 164
Deferred	760	1,171	456
Total Federal	626	596	620
State and Local:			
Current	(20)	(76)	(1)
Deferred	38	55	22
Total State and Local	18	(21)	21
International:			
Current	(1)	-	1
Deferred	-	-	-
Total International	(1)	-	1
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 643	$ 575	$ 642

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Income	$ 1,218	$ 1,365	$ 1,388
Discontinued Operations, Net of Income Tax of $(10) million in 2008	-	-	(12)
Extraordinary Loss, Net of Income Tax of $3 million in 2009	-	5	-
Income Before Discontinued Operations and Extraordinary Loss	1,218	1,370	1,376
Income Tax Expense Before Discontinued Operations and Extraordinary Loss	643	575	642
Pretax Income	$ 1,861	$ 1,945	$ 2,018
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 651	$ 681	$ 706
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	47	31	23
Investment Tax Credits, Net	(16)	(19)	(19)
Energy Production Credits	(20)	(15)	(20)
State and Local Income Taxes	11	(14)	13
Removal Costs	(19)	(19)	(21)
AFUDC	(33)	(36)	(24)
Medicare Subsidy	12	(11)	(12)
Tax Reserve Adjustments	(16)	(6)	2
Other	26	(17)	(6)
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 643	$ 575	$ 642
Effective Income Tax Rate	34.6 %	29.6 %	31.8 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2010	December 31, 2009
	(in millions)	
Deferred Tax Assets	$ 2,519	$ 2,493
Deferred Tax Liabilities	(10,009)	(9,065)
Net Deferred Tax Liabilities	$ (7,490)	$ (6,572)
Property-Related Temporary Differences	$ (5,301)	$ (4,714)
Amounts Due from Customers for Future Federal Income Taxes	(250)	(229)
Deferred State Income Taxes	(622)	(523)
Securitized Transition Assets	(651)	(712)
Regulatory Assets	(867)	(862)
Accrued Pensions	218	335
Deferred Income Taxes on Other Comprehensive Loss	207	203
Accrued Nuclear Decommissioning	(395)	(356)
All Other, Net	171	286
Net Deferred Tax Liabilities	$ (7,490)	$ (6,572)

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.

At December 31, 2010, we have federal general business credit carryforwards of $64 million. If these credits are not utilized, they will expire in the years 2028 through 2030.

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 federal 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. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and 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.

We sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, we accrued current federal, state and local income tax benefits in 2009. We realized the federal cash flow benefit in 2010 as there was sufficient capacity in prior periods to carry the net operating loss back. Most of our state and local jurisdictions do not provide for a net operating loss carry back. We anticipate future taxable income will be sufficient to realize the tax benefit. As such, we determined that a valuation allowance is unnecessary.

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Interest Expense	$ 8	$ 1	$ 10
Interest Income	11	5	21
Reversal of Prior Period Interest Expense	5	5	13

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31, 2010	2009
	(in millions)	
Accrual for Receipt of Interest	$ 42	$ 30
Accrual for Payment of Interest and Penalties	21	18

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2010	2009	2008
		(in millions)	
Balance at January 1,	$ 237	$ 237	$ 222
Increase - Tax Positions Taken During a Prior Period	40	56	41
Decrease - Tax Positions Taken During a Prior Period	(43)	(65)	(45)
Increase - Tax Positions Taken During the Current Year	-	16	27
Decrease - Tax Positions Taken During the Current Year	(6)	-	(5)
Increase - Settlements with Taxing Authorities	-	1	3
Decrease - Settlements with Taxing Authorities	(2)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	(7)	(8)	(6)
Balance at December 31,	$ 219	$ 237	$ 237

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $112 million, $137 million and $147 million for 2010, 2009 and 2008, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Under the Energy Tax Incentives Act of 2005, we filed applications with the United States Department of Energy and the IRS in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits. We had until July 2010 to meet certain minimum requirements under the agreement with the IRS or the credits would be forfeited. In July 2010, we forfeited the allocated tax credits.

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a cash flow benefit of approximately $200 million in 2008.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $419 million.

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 year ended December 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.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on net income or financial condition but had a favorable impact on cash flows of $318 million in 2010.

State Tax Legislation

Under Ohio House Bill 66, in 2005, the Ohio companies established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, regulatory assets associated with the deferred state income tax liabilities were reduced by $22 million. In November 2006, the PUCO ordered that the $57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet. As of December 31, 2008, the $57 million regulatory liability was fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax was phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $13 million, $11 million and $9 million were recorded in 2010, 2009 and 2008, respectively, in Taxes Other Than Income Taxes.

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which is calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The law also includes significant credits for engaging in Michigan-based activity.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Lease Expense on Operating Leases	$ 343	$ 354	$ 368
Amortization of Capital Leases	97	83	97
Interest on Capital Leases	26	13	16
Total Lease Rental Costs	$ 466	$ 450	$ 481

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2010	2009
	(in millions)	
Generation	$ 97	$ 75
Distribution	-	-
Other Property, Plant and Equipment	482	379
Construction Work in Progress	-	-
Total Property, Plant and Equipment Under Capital Leases	579	454
Accumulated Amortization	108	139
Net Property, Plant and Equipment Under Capital Leases	$ 471	$ 315
Obligations Under Capital Leases		
Noncurrent Liability	$ 398	$ 244
Liability Due Within One Year	76	73
Total Obligations Under Capital Leases	$ 474	$ 317

Future minimum lease payments consisted of the following at December 31, 2010:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2011	$ 100	$ 306
2012	88	286
2013	71	261
2014	59	241
2015	47	226
Later Years	286	1,349
Total Future Minimum Lease Payments	$ 651	$ 2,669
Less Estimated Interest Element	177	
Estimated Present Value of Future Minimum Lease Payments	$ 474	

Master Lease Agreements

We lease certain equipment under master lease agreements. In December 2010, we signed a new master lease agreement with GE Capital Commercial Inc. (GE) for approximately $137 million to replace existing operating and capital leases with GE. We refinanced approximately $60 million of capital leases and approximately $77 million in operating leases. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Approximately $16 million of currently leased assets were not included in the refinancing, but will be purchased or refinanced in 2011. In addition, approximately $40 million of operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% 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 84% of the unamortized balance. For equipment under other 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 December 31, 2010, the maximum potential loss for these lease agreements was approximately $14 million ($9 million, net of tax) 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.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2010 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2011	$ 74	$ 74
2012	74	74
2013	74	74
2014	74	74
2015	74	74
Later Years	517	517
Total Future Minimum Lease Payments	$ 887	$ 887

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 $17 million for I&M and $19 million for SWEPCo for the remaining railcars as of December 31, 2010. These obligations are included in the future minimum lease payments schedule earlier in this note.

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.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale and leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. In addition to the 2009 transactions, Sabine has one additional $53 million dragline completed in 2008 that was financed under a capital lease. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2010 and 2009 Consolidated Balance Sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2010 and 2009 Consolidated Balance Sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $3 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2010 and 2009 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2010 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**Amount (in millions)**
2011	$ 2
2012	1
Total Future Minimum Lease Payments	$ 3

14. FINANCING ACTIVITIES

AEP Common Stock

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

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2010, 2009 and 2008:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2007	421,926,696	21,499,992
Issued	4,394,552	-
Treasury Stock Contributed to AEP Foundation	-	(1,250,000)
Balance, December 31, 2008	426,321,248	20,249,992
Issued	72,012,017	-
Treasury Stock Acquired	-	28,866
Balance, December 31, 2009	498,333,265	20,278,858
Issued	2,781,616	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2010	501,114,881	20,307,725

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2010			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount
Not Subject to Mandatory Redemption:				(in millions)
4.00% - 5.00%	$102-$110	1,525,903	600,641	$ 60

	December 31, 2009			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount
Not Subject to Mandatory Redemption:				(in millions)
4.00% - 5.00%	$102-$110	1,525,903	606,627	$ 61

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares. If the subsidiary defaults on preferred stock dividend payments for a period of one year or longer, preferred stock holders are entitled, voting separately as one class, to elect the number of directors necessary to constitute a majority of the full board of directors of the subsidiary.

(b) As of December 31, 2010 and 2009, our subsidiaries had 14,494,227 and 14,488,294 shares of $100 par value preferred stock, respectively, 22,200,000 shares of $25 par value preferred stock and 7,822,535 and 7,822,482 shares of no par value preferred stock, respectively, that were authorized but unissued. Total shares authorized but unissued include shares not subject to mandatory redemption described in the above table.

(c) The number of preferred stock shares redeemed was 5,986 shares and 251 shares in 2010 and 2009, respectively. There were no preferred stock shares redeemed in 2008.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	2009	Outstanding at December 31, 2010	2009
				(in millions)	
Senior Unsecured Notes					
2010-2015	4.99%	0.702%-6.375%	0.464%-6.375%	$ 3,318	$ 4,258
2016-2021	6.12%	5.00%-7.95%	5.00%-7.95%	4,020	4,020
2029-2040	6.41%	5.625%-8.13%	5.625%-8.13%	4,331	4,138
Pollution Control Bonds (a)					
2010-2015 (b)	2.95%	0.29%-6.25%	0.22%-7.125%	1,300	800
2017-2025	5.12%	4.45%-6.05%	0.23%-6.05%	443	595
2026-2042	5.19%	4.40%-6.30%	0.20%-6.30%	520	764
Notes Payable (c)					
2011-2026	5.44%	2.07%-8.03%	4.47%-8.03%	396	326
Securitization Bonds					
2010-2020	5.36%	4.98%-6.25%	4.98%-6.25%	1,847	1,995
Junior Subordinated Debentures (d)					
2063	8.75%	8.75%	8.75%	315	315
Spent Nuclear Fuel Obligation (e)				265	265
Other Long-term Debt					
2011-2059	1.72%	1.3125%-13.718%	1.25%-13.718%	91	88
Unamortized Discount (net)				(35)	(66)
Total Long-term Debt Outstanding				16,811	17,498
Less Portion Due Within One Year				1,309	1,741
Long-term Portion				$ 15,502	$ 15,757

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013.

(e) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

At December 31, 2010, $50 million of PSO's Senior Unsecured Notes, which are due within one year, are classified as long-term debt due to our intent and ability to refinance these notes on a long-term basis. In January 2011, PSO issued $250 million of 4.4% Senior Unsecured Notes due in 2021, demonstrating the ability to refinance these obligations on a long-term basis.

At December 31, 2009, approximately $472 million of variable-rate, tax-exempt bonds were outstanding. These bonds, which are short-term obligations, were classified as long-term due to our intent and ability to refinance each obligation on a long-term basis. At December 31, 2009, our $478 million credit facility had non-cancelable terms in excess of one year, demonstrating the ability to refinance these short-term obligations on a long-term basis.

Long-term debt outstanding at December 31, 2010 is payable as follows:

	2011	2012	2013	2014	2015	After 2015	Total
				(in millions)			
Principal Amount	$ 1,309	$ 815	$ 1,344	$ 941	$ 1,490	$ 10,947	$ 16,846
Unamortized Discount							(35)
Total Long-term Debt Outstanding							$ 16,811

In January 2011, TCC retired $92 million of its outstanding Securitization Bonds.

In February 2011, APCo issued $65 million of 2% Pollution Control Bonds due in 2041 with a 2012 mandatory put date.

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

Dividend Restrictions

Parent 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.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

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, and are callable at par any time on or after March 1, 2013. 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.

Utility Subsidiaries' Restrictions

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. Specifically, most of our public utility subsidiaries have revolving credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. At December 31, 2010, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $7 billion.

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.

Lines of Credit and Short-term Debt

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. As of December 31, 2010, we had credit facilities totaling $3 billion to support our commercial paper program (see “Credit Facilities” section below). The maximum amount of commercial paper outstanding during 2010 was $868 million and the weighted average interest rate of commercial paper outstanding during the year was 0.43%. Our outstanding short-term debt was as follows:

	December 31,			
	2010		2009	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 690	0.31 %	$ -	-
Commercial Paper	650	0.52 %	119	0.26 %
Line of Credit – Sabine Mining Company (c)	6	2.15 %	7	2.06 %
Total Short-term Debt	$ 1,346		$ 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 the credit facility that matures in April 2012 as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities, which was scheduled to mature in March 2011, and replaced it with a new $1.5 billion credit facility which matures in June 2013 and allows for the issuance of up to $600 million as letters of credit. As of December 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million.

In June 2010, we reduced a $627 million credit agreement that matures in April 2011 to $478 million. Under the facility, we may issue letters of credit. As of December 31, 2010, $477 million of letters of credit were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. 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 Consolidated Balance Sheet. See “ASU 2009-16 ‘Transfers and Servicing’ ” section of Note 2 for discussion of the 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 financings. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies’ receivables and accelerate AEP Credit’s cash collections.

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

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2010	2009	2008
	(dollars in millions)		
Proceeds from Sale of Accounts Receivable	$ N/A	$ 7,043	$ 7,717
Loss on Sale of Accounts Receivable	N/A	3	20
Average Variable Discount Rate on Sale of Accounts Receivable	N/A	0.57 %	3.19 %
Effective Interest Rates on Securitization of Accounts Receivable	0.31 %	N/A	N/A
Net Uncollectible Accounts Receivable Written Off	22	28	23

	December 31,	
	2010	2009
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 923	$ 160
Deferred Revenue from Servicing Accounts Receivable	N/A	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	N/A	158
Retained Interest if 20% Adverse Change in Uncollectible Accounts	N/A	156
Total Principal Outstanding	690	656
Derecognized Accounts Receivable	N/A	631
Delinquent Securitized Accounts Receivable	50	29
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	26	20
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	354	376

N/A Not Applicable

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2010, 2009 or 2008 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

Stock Options	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Fair Value of Stock Options Vested	$ -	$ 25	$ 25
Intrinsic Value of Options Exercised (a)	2,058	106	655

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2010, 2009 and 2008 is as follows:

	2010		2009		2008	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding at January 1,	1,089	$ 32.78	1,128	$ 32.73	1,196	$ 32.69
Granted	-	N/A	-	N/A	-	N/A
Exercised/Converted	(448)	31.53	(21)	27.20	(68)	31.97
Forfeited/Expired	(90)	38.44	(18)	36.28	-	N/A
Outstanding at December 31,	551	32.88	1,089	32.78	1,128	32.73
Options Exercisable at December 31,	551	$ 32.88	1,089	$ 32.78	1,125	$ 32.72

The following table summarizes information about AEP stock options outstanding and exercisable at December 31, 2010:

2010 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06-27.95	266	2.20	$ 27.44	$ 2,273
$30.76-38.65	159	3.10	31.26	778
$44.10-49.00	126	0.50	46.40	-
Total	551	2.08	32.88	3,051

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a value upon vesting equal to the market value of shares of AEP common stock. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. For the three-year performance and vesting period ending in 2009 and earlier performance periods, performance units are paid in cash or stock at the employee's election unless they are needed to satisfy a participant's stock ownership requirement. Starting with the three-year performance and vesting period ending in 2010 and later, performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that have a value equivalent to shares of AEP common stock and are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and

AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2010, 2009 and 2008 as follows:

	Years Ended December 31,		
Performance Units	**2010**	**2009**	**2008**
Awarded Units (in thousands)	736	1,179	1,384
Weighted Average Unit Fair Value at Grant Date	$ 35.43	$ 34.32	$ 30.11
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares	Years Ended December 31,		
(Reinvested Dividends Portion)	**2010**	**2009**	**2008**
Awarded Units (in thousands)	211	224	149
Weighted Average Grant Date Fair Value	$ 34.70	$ 28.82	$ 37.21
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the utility industry segment of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 business days of the performance period.

The certified performance scores and units earned for the three-year period ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
	2010	**2009**	**2008**
Certified Performance Score	55.8 %	73.5 %	120.3 %
Performance Units Earned	489,013	593,175	1,088,302
Performance Units Manditorily Deferred as AEP Career Shares	33,501	26,635	42,214
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	6,583	27,855	66,415
Performance Units to be Paid in Cash	448,929	538,685	979,673

The cash payouts for the years ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Cash Payouts for Performance Units	$ 18,683	$ 30,034	$ 52,960
Cash Payouts for AEP Career Share Distributions	3,594	2,184	1,236

Restricted Shares and Restricted Stock Units

The independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005, 50,000 vested on January 1, 2006, 66,666 vested on November 30, 2009 and 66,667 vested on November 30, 2010. The remaining 66,667 restricted shares will vest on November 30, 2011, subject to his continued AEP employment through that date. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum term for these restricted shares is eight years and dividends on these restricted shares are paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. For awards granted prior to 2009, additional RSUs granted as dividends vest on the last vesting date associated with that RSU grant. For awards granted in 2009 and later, additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is five years from the grant date.

In 2010, the HR Committee granted a total of 165,520 of RSUs to four CEO succession candidates to better ensure the retention of these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2010, 2009 and 2008 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2010**	**2009**	**2008**
Awarded Units (in thousands)	873	130	56
Weighted Average Grant Date Fair Value	$ 35.24	$ 29.29	$ 41.69

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
Restricted Shares and Restricted Stock Units	**2010**	**2009**	**2008**
		(in thousands)	
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 6,044	$ 6,573	$ 2,619
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	5,993	5,445	2,534

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2010 and changes during the year ended December 31, 2010 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Nonvested at January 1, 2010	366	$ 34.12
Granted	873	35.24
Vested	(173)	35.00
Forfeited	(40)	35.01
Nonvested at December 31, 2010	1,026	34.88

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2010 was $37 million and the weighted average remaining contractual life was 3.09 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The non-employee directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2010, 2009 and 2008.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2010, 2009 and 2008 as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2010**	**2009**	**2008**
Awarded Units (in thousands)	54	56	43
Weighted Average Grant Date Fair Value	$ 34.67	$ 29.56	$ 37.72

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2010**	**2009**	**2008**
		(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 28,116	$ 31,165	$ (18,028)(b)
Actual Tax Benefit Realized	9,841	10,908	(6,310)(b)
Total Compensation Cost Capitalized	4,689	5,956	(5,026)(b)

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on our Consolidated Statements of Income.
(b) In 2008, AEP's declining total shareholder return and lower stock price significantly reduced the accruals for performance units.

During the years ended December 31, 2010, 2009 and 2008, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2010, there was $81 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.84 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2010, 2009 and 2008 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2010	2009	2008
	(in thousands)		
Cash Received from Stock Options Exercised	$ 14,134	$ 567	$ 2,170
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	706	35	219

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we could use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset AEP's tax withholding obligation.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 14,147	$ 6,537	1.6 - 3.8 %	9 - 132	$ 10,205	$ 3,788	2.2 - 5.1 %	20 - 70
Transmission	8,576	2,481	1.4 - 3.0 %	25 - 87	-	-	- - - %	- - -
Distribution	14,208	3,607	2.4 - 3.9 %	11 - 75	-	-	- - - %	- - -
CWIP	2,615 (a)	47	N.M.	N.M.	143	9	N.M.	N.M.
Other	2,685	1,268	3.0 - 12.5 %	5 - 55	1,161	329	N.M.	N.M.
Total	$ 42,231	$ 13,940			$ 11,509	$ 4,126		

2009	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 13,047	$ 6,460	1.6 - 3.8 %	9 - 132	$ 9,998	$ 3,479	1.9 - 3.3 %	20 - 70
Transmission	8,315	2,478	1.4 - 2.7 %	25 - 87	-	-	- - - %	- - -
Distribution	13,549	3,421	2.4 - 3.9 %	11 - 75	-	-	- - - %	- - -
CWIP	2,866 (a)	(19)	N.M.	N.M.	165	6	N.M.	N.M.
Other	2,616	1,130	4.2 - 12.8 %	5 - 55	1,128	385	N.M.	N.M.
Total	$ 40,393	$ 13,470			$ 11,291	$ 3,870		

2008	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.6 - 3.5 %	9 - 132	2.6 - 5.1 %	20 - 61
Transmission	1.4 - 2.7 %	25 - 87	- - - %	- - -
Distribution	2.4 - 3.9 %	11 - 75	- - - %	- - -
CWIP	N.M.	N.M.	N.M.	N.M.
Other	4.9 - 11.3 %	5 - 55	N.M.	N.M.

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

N.M. Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For rate-regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

As of January 1, 2010, DHLC was deconsolidated and is now reported as an equity investment on our Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2010 and 2009 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO at December 31, 2008	$ 1,158
Accretion Expense	73
Liabilities Incurred	47
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	5
ARO at December 31, 2009 (a)	1,259
DHLC Deconsolidation (c)	(12)
Accretion Expense	75
Liabilities Incurred	32
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	64
ARO at December 31, 2010 (b)	$ 1,398

(a) The current portion of our ARO, totaling $5 million, is included in Other Current Liabilities on our 2009 Consolidated Balance Sheet.

(b) The current portion of our ARO, totaling $4 million, is included in Other Current Liabilities on our 2010 Consolidated Balance Sheet.

(c) We adopted ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. As a result, we record only 50% of the final reclamation based on our share of the obligation instead of the previous 100%.

As of December 31, 2010 and 2009, our ARO liability was $1.4 billion and $1.3 billion, respectively, and included $930 million and $878 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2010 and 2009, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.2 billion and $1.1 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 77	$ 82	$ 45
Allowance for Borrowed Funds Used During Construction	53	67	75

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Income and the investments and accumulated depreciation are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

			Company's Share at December 31, 2010		
	Fuel Type	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	8	49
J.M. Stuart Generating Station (c)	Coal	26.0 %	507	23	163
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	10	366
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	258	5	192
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	7	62
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	503	10	358
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	395	4	201
Turk Generating Plant (h)	Coal	73.33 %	-	971	-
Transmission	N/A	(d)	63	3	48

			Company's Share at December 31, 2009		
	Fuel Type	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	4	45
J.M. Stuart Generating Station (c)	Coal	26.0 %	499	15	153
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	767	4	355
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	255	4	188
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	5	61
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	497	8	350
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	390	6	195
Turk Generating Plant (h)	Coal	73.33 %	-	688	-
Transmission	N/A	(d)	70	1	47

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Operated by PSO and also jointly-owned (54.7%) by TNC.
(f) Operated by CLECO, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2010, construction costs totaling $279 million have been billed to the other owners.
N/A Not Applicable

17. COST REDUCTION INITIATIVES

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. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. We do not expect additional costs to be incurred related to this initiative.

	Total
	(in millions)
Incurred	$ 293
Settled	283
Adjustments	7
Remaining Balance at December 31, 2010	$ 17

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Consolidated Statements of Income and Other Current Liabilities on the Consolidated Balance Sheets. Approximately 99% of the expense was within the Utility Operations segment.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our net income for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2010 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,569	$ 3,360	$ 4,064	$ 3,434
Operating Income	758	394 (a)	1,025	486 (b)
Net Income	346	137 (a)	557	178 (b)
Amounts Attributable to AEP Common Shareholders:				
Net Income	344	136 (a)	555	176 (b)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (c)	0.72	0.28	1.16	0.37
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (c)	0.72	0.28	1.16	0.37

	2009 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,458	$ 3,202	$ 3,547	$ 3,282
Operating Income	750	682	858	481
Income Before Extraordinary Loss	363	322	446	239
Extraordinary Loss, Net of Tax	-	(5)(d)	-	-
Net Income	363	317	446	239
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Loss	360	321	443	238
Extraordinary Loss, Net of Tax	-	(5)(d)	-	-
Net Income	360	316	443	238
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Loss (c)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (c)	0.89	0.67	0.93	0.49
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Loss (c)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (c)	0.89	0.67	0.93	0.49

(a) See Note 17 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.
(b) Includes a $43 million refund provision for the 2009 Significantly Excessive Earnings Test in addition to various other provisions for certain regulatory and legal matters.
(c) Quarterly Earnings Per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(d) See "SWEPCo Texas Restructuring" in "Extraordinary Item" section of Note 2 for discussion of the extraordinary loss recorded in the second quarter of 2009.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/directstockpurchase.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Julie Sherwood, 614-716-2663, jasherwood@AEP.com; or Sara Macioch, 614-716-2835, semacioch@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of December 31, 2010, there were approximately 91,000 registered shareholders and approximately 331,000 shareholders holding stock in street name through a bank or broker. There were 480,807,156 shares outstanding at December 31, 2010.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2010. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Michael G. Morris	64	Chairman of the Board and Chief Executive Officer
Nicholas K. Akins	50	President
Carl L. English	64	Vice Chairman
D. Michael Miller	63	Senior Vice President, General Counsel and Secretary
Robert P. Powers	56	President – AEP Utilities
Brian X. Tierney	43	Executive Vice President and Chief Financial Officer
Susan Tomasky	57	President – AEP Transmission