Appendix A to the
Proxy Statement

American Electric Power

2012 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AEP
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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., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
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, an AEP 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.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, 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.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.

Term	Meaning
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company America Transco, LLC 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 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.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, 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.
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 transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NEIL	Nuclear Electric Insurance Limited insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.

Term	Meaning
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.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, 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 1,310 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEET	Significantly Excessive Earnings Test.
SEC	U.S. Securities and Exchange Commission.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III 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, a 600 MW pulverized coal ultra-supercritical generating unit in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
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 Discussion and Analysis of Financial Condition and Results of Operations," 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 are presented 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, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- 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 drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission lines and 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 nuclear generation, 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 and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- 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, coal, natural gas and other energy-related commodities.
- 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.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for electricity, coal, natural gas and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the transition to market and expected legal separation for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- 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 our debt.
- 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.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

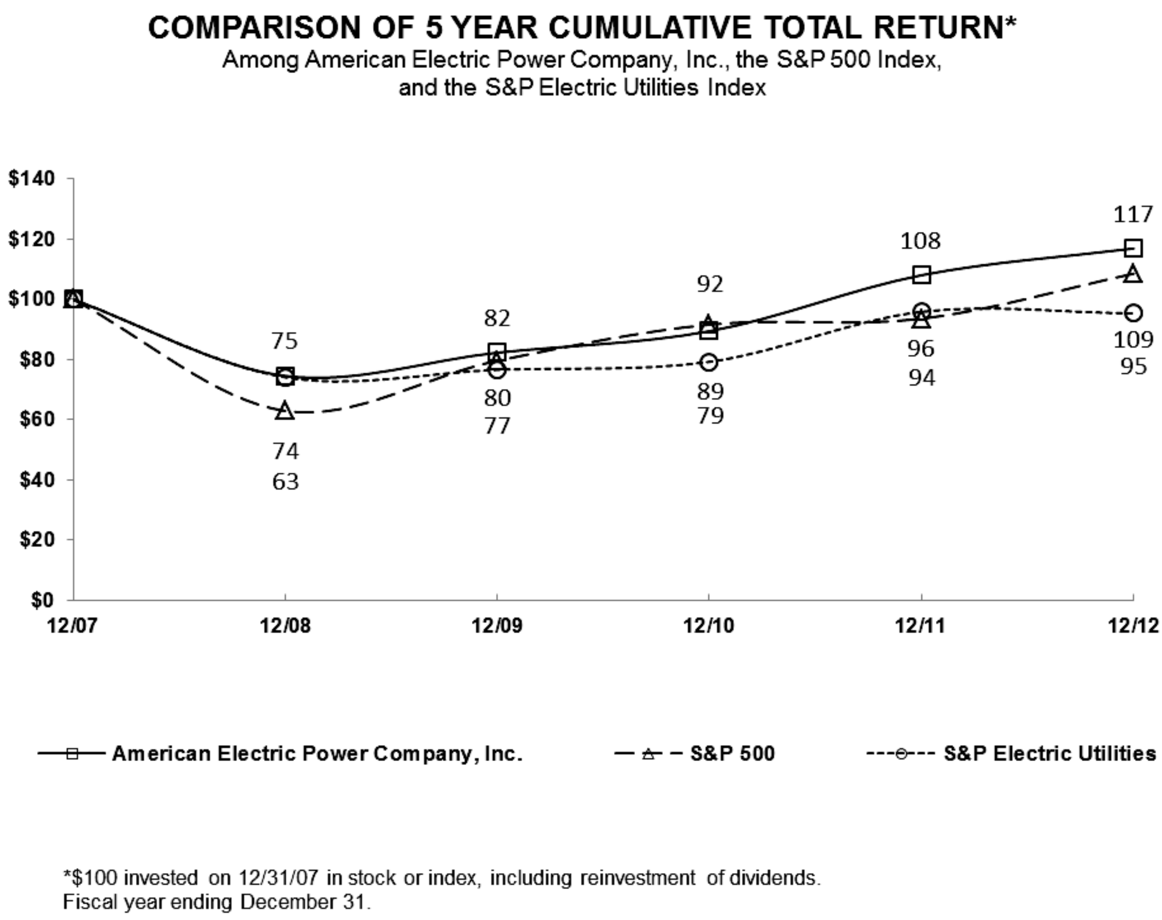
The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of this report.

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, 2012	$ 45.41	$ 40.56	$ 42.68	$ 0.47
September 30, 2012	44.84	39.62	43.94	0.47
June 30, 2012	40.46	36.97	39.90	0.47
March 31, 2012	41.98	37.46	38.58	0.47
December 31, 2011	$ 41.71	$ 35.85	$ 41.31	$ 0.47
September 30, 2011	38.98	33.09	38.02	0.46
June 30, 2011	38.99	34.37	37.68	0.46
March 31, 2011	36.92	33.47	35.14	0.46

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2012, AEP had approximately 83,000 registered shareholders.



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

	2012	2011	2010	2009	2008
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,945	$ 15,116	$ 14,427	$ 13,489	$ 14,440
Operating Income	$ 2,656	$ 2,782	$ 2,663	$ 2,771	$ 2,787
Income Before Discontinued Operations and Extraordinary Items	$ 1,262	$ 1,576	$ 1,218	$ 1,370	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	-	12
Income Before Extraordinary Items	1,262	1,576	1,218	1,370	1,388
Extraordinary Items, Net of Tax	-	373	-	(5)	-
Net Income	1,262	1,949	1,218	1,365	1,388
Net Income Attributable to Noncontrolling Interests	3	3	4	5	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214	1,360	1,383
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211	$ 1,357	$ 1,380
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 57,454	$ 55,670	$ 53,740	$ 51,684	$ 49,710
Accumulated Depreciation and Amortization	18,691	18,699	18,066	17,340	16,723
Total Property, Plant and Equipment – Net	$ 38,763	$ 36,971	$ 35,674	$ 34,344	$ 32,987
Total Assets	$ 54,367	$ 52,223	$ 50,455	$ 48,348	$ 45,155
Total AEP Common Shareholders' Equity	$ 15,237	$ 14,664	$ 13,622	$ 13,140	$ 10,693
Noncontrolling Interests	$ -	$ 1	$ -	$ -	$ 17
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ -	$ 60	$ 61	$ 61
Long-term Debt (a)	$ 17,757	$ 16,516	$ 16,811	$ 17,498	$ 15,983
Obligations Under Capital Leases (a)	$ 449	$ 458	$ 474 (b)	$ 317	$ 325
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Items	$ 2.60	$ 3.25	$ 2.53	$ 2.97	$ 3.40
Discontinued Operations, Net of Tax	-	-	-	-	0.03
Income Before Extraordinary Items	2.60	3.25	2.53	2.97	3.43
Extraordinary Items, Net of Tax	-	0.77	-	(0.01)	-
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.60	$ 4.02	$ 2.53	$ 2.96	$ 3.43
Weighted Average Number of Basic Shares Outstanding (in millions)	485	482	479	459	402
Market Price Range:					
High	$ 45.41	$ 41.71	$ 37.94	$ 36.51	$ 49.11
Low	$ 36.97	$ 33.09	$ 28.17	$ 24.00	$ 25.54
Year-end Market Price	$ 42.68	$ 41.31	$ 35.98	$ 34.79	$ 33.28
Cash Dividends Declared per AEP Common Share	$ 1.88	$ 1.85	$ 1.71	$ 1.64	$ 1.64
Dividend Payout Ratio	72.31%	46.02%	67.59%	55.41%	47.8%
Book Value per AEP Common Share	$ 31.35	$ 30.36	$ 28.32	$ 27.49	$ 26.35

(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.

Our subsidiaries operate an extensive portfolio of assets including:

- Almost 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- Approximately 40,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 221,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 7,600 railcars, approximately 3,100 barges, 60 towboats, 25 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 42 million tons of coal and dry bulk commodities. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 18% for steel and 14% for other commodities.

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. See the "Turk Plant" section of Note 3.

Sustainable Cost Reductions

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to conduct an organizational and process optimization evaluation and a second firm to evaluate our current employee benefit programs. We recorded a charge to expense of $47 million ($30 million, net of tax) in 2012 related primarily to severance benefits. We expect to complete the final phase of the sustainable cost reduction program by the end of the first quarter of 2013. Going forward, we anticipate that this program provides a behavioral foundation upon which additional process improvement projects will be implemented as a regular business practice. At this time, we are unable to estimate the total amount to be incurred in future periods related to this initiative or to quantify the effects on future earnings, cash flows and financial condition.

Retiree Medical Contribution Changes

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage will be capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. For 2013, we estimate these changes will result in a decrease of Other Operation and Maintenance expenses of approximately $80 million.

Financing Changes

In December 2012, we retired $558 million of Parent debt with part of the proceeds of an issuance of $850 million of Senior Unsecured Notes. Expenses associated with the early retirement of debt were approximately $50 million in 2012 with annual savings of approximately $30 million per year in 2013 and 2014.

In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

Ohio Plant Impairments

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement, we performed an evaluation of the recoverability of generation assets using generating unit specific estimated future cash flows and concluded that OPCo had a material impairment of certain generation assets. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million ($185 million, net of tax) in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units and related material and supplies inventory.

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo’s generation assets including the transfer of OPCo’s generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers’ Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo’s generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo’s current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo’s Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval of the Amos Plant and Mitchell Plant transfers discussed above. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Also in December 2012, KPCo filed a request with the KPSC for approval of the Mitchell Plant transfer discussed above. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. In addition, KPCo announced its plan to retire Big Sandy Plant, Unit 2 in early 2015 and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

Our results of operations related to generation in Ohio will be largely determined by prevailing market conditions.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause, adopted a 12% earnings threshold for the SEET and established a non-bypassable Distribution Investment Rider (DIR) effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. The capacity order, including collection of capacity costs, has been appealed to the Supreme Court of Ohio.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its deferred capacity costs and ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition. See “Ohio Electric Security Plan Filing” section of Note 3.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. As a result, we lost approximately $235 million of gross margin in 2012 as compared to 2011. This reduction in gross margin is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) Retail Stability Rider collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation and Marketing segment which targets retail customers, both within and outside of our retail service territory. As of December 31, 2012, based upon an average annual load, approximately 51% of our Ohio load had switched to CRES providers.

Customer Demand

In comparison to 2011, cooling degree days in 2012 were down 6% in our western region and up 4% in our eastern region. Heating degree days in 2012 were down in our western and eastern regions by 36% and 15%, respectively. Our weather-normalized retail sales were down 0.7% compared to 2011. Our industrial sales declined 0.9% partially due to Ormet, a large aluminum company that lowered their production in the third quarter of 2012 by one-third. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware.

In 2013, we anticipate slight increases in retail sales in our eastern region related to shale gas development and processing and in our western region related to oil and gas extraction. We also anticipate decreases in industrial demand in our eastern region related to Ormet’s lower production levels discussed above.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. In the fourth quarter of 2012, the Supreme Court of Ohio upheld the PUCO decision on the 2009 SEET filing. Subsequent testimony and legal briefs from intervenors recommended refunds of a portion of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo. See "Ohio Electric Security Plan Filing" section of Note 3.

Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the acceleration of the retirement date of Tanners Creek Plant, Units 1-3. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve. See "2011 Indiana Base Rate Case" section of Note 3.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In December 2012, several intervenors filed opposing testimony with various recommendations. A decision from the PUCT is expected in the second quarter of 2013. See "2012 Texas Base Rate Case" section of Note 3.

Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

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 cost approximately $400 million. In February 2013, we signed an agreement and received payment from NEIL, the insurer, to settle the remaining claims. The settlement did not have a material impact on net income, cash flows or financial condition. See "Cook Plant, Unit 1 Fire and Shutdown" section of Note 5.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC. Several intervenors filed testimony in Indiana with various recommendations including caps on expenditures. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition. See "Cook Plant Life Cycle Management Project" section of Note 3.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with 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 (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

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, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2012, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $4 billion to $5 billion between 2012 and 2020. These amounts include investments to convert 1,555 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, these units could be retired sooner than planned.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (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, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon our continuing evaluation, we have given notice to the applicable RTOs of our intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
KPCo	Big Sandy Plant, Unit 1	278
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528
Total		4,441

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (53 MWs) of one unit at that station.

KPCo notified the KPSC of its plan to retire Big Sandy Plant, Unit 2 in early 2015 and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

In September 2012, based upon an agreement in principle with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC to retire Units 3 and 4 of the Northeastern Station, a total of 930 MWs, in 2026 and 2016, respectively. See "Oklahoma Environmental Compliance Plan" and "Regional Haze" sections below.

In December 2012, we retired OPCo's 165 MW Conesville Plant, Unit 3.

A decline in natural gas prices, pending environmental rules and the proposed termination of the Interconnection Agreement had an adverse impact on the recoverability of the net book values of certain coal-fired units. In 2012, we recorded a $287 million pretax impairment charge for OPCo's net book value of certain plants totaling 1,870 MWs in the table above and the Beckjord and Conesville plants discussed above. See "Impairments" section of Note 6.

We are still evaluating our plans for and the timing of conversion of some of our coal units to natural gas, installing emission control equipment on other units and closure of existing units based on changes in emission requirements and demand for power. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could reduce future net income and cash flows.

Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle all claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

The consent decree requires certain types of control equipment to be installed at Muskingum River Plant, Unit 5 and Big Sandy Plant, Unit 2 in 2015 and the two units of the Rockport Plant in 2017 and 2019. In February 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the modification include more options for the affected units (including alternative control technologies, re-fueling and/or retirement), more stringent SO_2 emission caps for the AEP System and additional mitigation measures. The Federal EPA will seek public comments on the modification prior to its entry by the court. Under the terms of the modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028. Muskingum River Plant, Unit 5 will have options to cease burning coal and retire in 2015 or cease burning coal in 2015 and complete a refueling project no later than June 2017. Big Sandy Plant, Unit 2 will have options to retrofit, retire, repower or refuel by 2015. I&M will secure an additional 200 MWs of renewable power resources by December 2014 and provide $8.5 million for additional mitigation projects.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, we have incurred $71 million related to these environmental controls, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows. In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. See the "Modification of the NSR Litigation Consent Decree" section above and the "Rockport Plant Environmental Controls" section of Note 3.

Big Sandy Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Unit 2 with a dry FGD system. As part of the Mitchell Plant transfer filing discussed above under "Corporate Separation, Plant Transfers and Application to Amend Sharing Agreement", KPCo requested costs related to the FGD project be established as a regulatory asset and recovered in KPCo's next base rate case. As of December 31, 2012, KPCo has incurred $29 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet. See "Big Sandy Plant, Unit 2 FGD System" section of Note 3.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014. In January 2013, several parties filed testimony with various recommendations. A hearing is scheduled for April 2013. See "Oklahoma Environmental Compliance Plan" section of Note 3.

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.

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 District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The United States Court of Appeals for the District of Columbia Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. In August 2012, a panel of the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in February 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply 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 state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO_2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the United States Court of Appeals for the District of Columbia Circuit and its fate is uncertain given recent developments in the CSAPR litigation.

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. 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 electric utility units and agreed to specific deadlines to issue proposed new source performance standards for utility boilers.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_x, lead and PM, and is currently reviewing the NAAQS for ozone. 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.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "over control" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents filed petitions for rehearing but in January 2013, the United States Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required 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. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In November 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. It is uncertain whether any of the information generated during the reconsideration process will affect the standards for existing sources.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the United States Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is proceeding on the remaining issues and briefing is scheduled to be completed by April 2013.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA proposed a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. Notice of the proposed settlement was published in the Federal Register in November 2012 and the comment period has closed. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement.

CO_2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO_2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO_2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources and does not apply to units whose CO_2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. The comment period closed in June 2012. New source performance standards affect units that have not yet received permits, but complete the permitting process while the proposal is pending. The proposed standards were challenged in the United States Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken. The Federal EPA is expected to finalize these standards in 2013.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase-in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. Petitioners may seek further review in the U.S. Supreme Court.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO_2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

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 coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another 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. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities.

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 under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is not expected until June 2013. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule is expected in 2013 and a final rule in 2014. We are unable to predict the impact of these changes but expect the costs to be significant.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, 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.

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.

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. 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 the end of 2012, we secured, through power purchase agreements, 1,994 MW of wind and solar power.

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. We estimate that our 2012 emissions were approximately 122 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 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 5.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 could 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. Public perception may ultimately have a significant impact on future legislation and regulation that could adversely affect our ability to recover our investments in coal-fired plants.

Climate change and its resultant impact on weather patterns could modify our customers' power usage. Our customers' energy needs currently vary with weather conditions and the economy. Increased or decreased energy usage could require the acquisition or construction of more generation and transmission assets or cause early retirement of such assets. The timing and duration of extreme weather conditions may require more system backup and contribute to increased system stresses, including service interruptions and increased storm restoration costs. 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 and higher margins.

To the extent climate change affects a region's economic health, it could also affect 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 the generation, transmission and distribution of electricity. 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. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

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

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The table below presents Income Before Extraordinary Item by segment for the years ended December 31, 2012, 2011 and 2010.

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Utility Operations	$ 1,299	$ 1,549	$ 1,192
Transmission Operations	43	30	9
AEP River Operations	15	45	37
Generation and Marketing	7	14	25
All Other (a)	(102)	(62)	(45)
Income Before Extraordinary Item	$ 1,262	$ 1,576	$ 1,218

(a) While not considered a reportable 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 were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

AEP CONSOLIDATED

2012 Compared to 2011

Income Before Extraordinary Item decreased from $1,576 million in 2011 to $1,262 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- The 2012 impairment for certain Ohio generation plants.
- The loss of retail customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- Expenses associated with the early retirement of Parent debt in 2012.
- Expenses related to the 2012 sustainable cost reductions.
- The 2012 adjustment of a UK windfall tax provision as a result of a recent related Supreme Court case.

These decreases were partially offset by:

- Successful rate proceedings in our various jurisdictions.
- Lower spending in 2012 as a result of our cost containment efforts.
- A 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.
- The 2011 plant impairments for Sporn Plant Unit 5 and for the FGD project at Muskingum River Plant Unit 5.
- The 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A loss incurred in 2011 related to a settlement of litigation with BOA and Enron.

Average basic shares outstanding increased to 485 million in 2012 from 482 million in 2011. Actual shares outstanding were 486 million as of December 31, 2012.

2011 Compared to 2010

Income Before Extraordinary Item increased from $1,218 million in 2010 to $1,576 million in 2011 primarily due to:

- An increase in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- A decrease in expenses as a result of the 2010 cost reduction initiatives.
- Successful rate proceedings in our various jurisdictions.

These increases were partially offset by:

- The loss of retail customers in Ohio to various CRES providers.
- Various Ohio adjustments in 2011, including:
  - The plant impairments for Sporn Plant Unit 5 and for the FGD project at Muskingum River Plant Unit 5.
  - A net decrease due to unfavorable Ohio regulatory orders in 2011.
  - The recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- A 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.

Average basic shares outstanding increased from 479 million in 2010 to 482 million in 2011. Actual shares outstanding were 483 million as of December 31, 2011.

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,		
	2012	2011	2010
		(in millions)	
Revenues	$ 13,778	$ 14,200	$ 13,792
Fuel and Purchased Electricity	4,963	5,455	4,996
Gross Margin	8,815	8,745	8,796
Other Operation and Maintenance	3,352	3,539	3,760
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,734	1,613	1,598
Taxes Other Than Income Taxes	828	812	811
Operating Income	2,601	2,642	2,627
Interest and Investment Income	7	29	9
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	78	91	77
Interest Expense	(882)	(886)	(942)
Income Before Income Tax Expense and Equity Earnings	1,857	2,269	1,841
Income Tax Expense	560	722	651
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Income Before Extraordinary Item	$ 1,299	$ 1,549	$ 1,192

Summary of KWh Energy Sales for Utility Operations

	Years Ended December 31,		
	2012	2011	2010
	(in millions of KWhs)		
Retail:			
Residential	58,780	61,655	61,944
Commercial	50,464	50,767	50,748
Industrial	59,154	59,667	57,333
Miscellaneous	3,072	3,100	3,083
Total Retail (a)	171,470	175,189	173,108
Wholesale	41,892	40,519	32,581
Total KWhs	213,362	215,708	205,689

(a) Represents energy delivered to distribution customers.

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,		
	2012	2011	2010
	(in degree days)		
Eastern Region			
Actual - Heating (a)	2,382	2,794	3,222
Normal - Heating (b)	2,987	2,980	2,983
Actual - Cooling (c)	1,258	1,215	1,307
Normal - Cooling (b)	1,029	1,017	1,002
Western Region			
Actual - Heating (a)	654	1,029	1,112
Normal - Heating (b)	984	984	980
Actual - Cooling (d)	2,852	3,020	2,515
Normal - Cooling (b)	2,372	2,349	2,339

(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.

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2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Utility Operations Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$	1,549
Changes in Gross Margin:		
Retail Margins		23
Off-system Sales		(19)
Transmission Revenues		83
Other Revenues		(17)
Total Change in Gross Margin		70
Changes in Expenses and Other:		
Other Operation and Maintenance		187
Asset Impairments and Other Related Charges		(161)
Depreciation and Amortization		(121)
Taxes Other Than Income Taxes		(16)
Interest and Investment Income		(22)
Carrying Costs Income		(340)
Allowance for Equity Funds Used During Construction		(13)
Interest Expense		4
Total Change in Expenses and Other		(482)
Income Tax Expense		162
Year Ended December 31, 2012	$	1,299

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 electricity were as follows:

- **Retail Margins** increased $23 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $177 million rate increase for OPCo.
    - An $87 million rate increase for APCo.
    - A $17 million rate increase for I&M.
    - A $13 million rate increase for PSO.
    - An $11 million rate increase for WPCo.

      For the rate increases described above, $156 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $71 million decrease in other variable electric generation expenses.
  - A $35 million increase due to OPCo's 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
  - A $33 million decrease in recoverable PJM expenses in Ohio.
  - A $24 million write-off in 2011 related to APCo's disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of the November 2011 Virginia SCC order.
  - A $9 million deferral of APCo's additional wind purchase costs as a result of the June 2012 Virginia SCC fuel factor order.
  - A $9 million increase due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

These increases were partially offset by:

- A $289 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
- A $95 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 15% and 36%, respectively, in heating degree days and a 6% decrease in cooling degree days in our western region.
- An $85 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

- **Margins from Off-system Sales** decreased $19 million primarily due to lower market prices, lower PJM capacity payments and reduced trading and marketing margins, partially offset by higher Ohio CRES capacity revenues.
- **Transmission Revenues** increased $83 million primarily due to net rate increases in ERCOT and increased transmission revenues from Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.
- **Other Revenues** decreased $17 million primarily due to a decrease in gains on miscellaneous sales, partially offset by an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase in revenues from securitization bonds is partially offset by an increase in Depreciation and Amortization expense.

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

- **Other Operation and Maintenance** expenses decreased $187 million primarily due to the following:
  - A $141 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $72 million decrease in nonutility operations and distribution expenses due to prior year cost reduction measures.
  - A $70 million decrease related to the 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
  - A $41 million decrease due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $16 million decrease in administrative and general expenses.
  - A $13 million decrease due to APCo's deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC recovered dollar-for-dollar within Gross Margin.

  These decreases were partially offset by:
  - A $44 million increase due to expenses related to the 2012 sustainable cost reductions.
  - A $42 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $33 million increase due to the 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC.
  - A $27 million increase due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $15 million increase in storm-related expenses due to major storms in our eastern region.
  - An $11 million gain from the sale of land in January 2011.
- **Asset Impairments and Other Related Charges** increased $161 million primarily due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.
  - A 2012 write-off of an additional $13 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.

This increase was partially offset by:
- A 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
- A 2011 plant impairment of $42 million for FGD project at Muskingum River Plant Unit 5.

- **Depreciation and Amortization** expenses increased $121 million primarily due to the following:
  - A $58 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - A $51 million increase due to TCC's issuance of securitization bonds in March 2012. The increase in TCC’s securitization related amortization is offset within Gross Margin.
  - A $48 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.
  - An $18 million increase in amortization primarily as a result of the Virginia Environmental Rate Adjustment Clause and the Virginia E&R surcharge, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - An $11 million increase in amortization of OPCo's Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $39 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $28 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate.
  - A $23 million decrease due to OPCo's amortization of carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income.
  - A $13 million decrease in OPCo's depreciation due to the 2011 plant impairment of Sporn Plant Unit 5.
- **Taxes Other Than Income Taxes** increased $16 million primarily due to increased property taxes as a result of increased capital investments.
- **Interest and Investment Income** decreased $22 million primarily due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- **Carrying Costs Income** decreased $340 million primarily due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** decreased $13 million primarily due to the completion of APCo's Dresden Plant in January 2012 and I&M's nuclear fuel preparation for usage, partially offset by increases related to SWEPCo's construction of the Turk Plant.
- **Interest Expense** decreased $4 million primarily due to lower long-term interest rates.
- **Income Tax Expense** decreased $162 million primarily due to a decrease in pretax book income, partially offset by the recording of federal and state income tax adjustments.

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2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Income from Utility Operations Before Extraordinary Item
(in millions)

Year Ended December 31, 2010	$	1,192
Changes in Gross Margin:		
Retail Margins		(139)
Off-system Sales		44
Transmission Revenues		48
Other Revenues		(4)
Total Change in Gross Margin		(51)
Changes in Expenses and Other:		
Other Operation and Maintenance		221
Asset Impairments and Other Related Charges		(139)
Depreciation and Amortization		(15)
Taxes Other Than Income Taxes		(1)
Interest and Investment Income		20
Carrying Costs Income		323
Allowance for Equity Funds Used During Construction		14
Interest Expense		56
Total Change in Expenses and Other		479
Income Tax Expense		(71)
Year Ended December 31, 2011	$	1,549

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

- **Retail Margins** decreased $139 million primarily due to the following:
  - A $132 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - An $87 million decrease in weather-related usage in our eastern region primarily due to a 13% decrease in heating degree days and a 7% decrease in cooling degree days.
  - An $84 million decrease in rate related margins for APCo due to the expiration of E&R cost recovery in Virginia.
  - A $60 million decrease due to the elimination of POLR charges, effective June 2011, in Ohio as a result of the October 2011 PUCO remand order.
  - A $51 million net decrease due to unfavorable Ohio and Virginia regulatory orders.
  - A $30 million increase in other variable electric generation expenses.

  These decreases were partially offset by:
  - Successful rate proceedings in our service territories which include:
    - A $120 million rate increase for OPCo.
    - A $63 million rate increase for APCo.
    - A $30 million rate increase for SWEPCo.
    - A $27 million rate increase for KPCo.
    - A $27 million rate increase for I&M.

    For the rate increases described above, $78 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $38 million increase in weather-related usage in our western region primarily due to a 20% increase in cooling degree days, slightly offset by a 7% decrease in heating degree days.

  - A $30 million increase due to increased SWEPCo gross margin from sales to customers previously served by Valley Electric Membership Corporation (VEMCO). SWEPCo acquired VEMCO assets and began serving VEMCO customers in October 2010.
  - A $14 million increase related to TCC's Transition Funding. This increase is offset by an increase in Depreciation and Amortization expenses.
- **Margins from Off-system Sales** increased $44 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $48 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.

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

- **Other Operation and Maintenance** expenses decreased $221 million primarily due to the following:
  - A $280 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
  - A $54 million decrease due to the 2010 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.
  - A $42 million decrease in administrative and general expenses primarily due to a decrease in fringe benefit expenses.
  - A $33 million decrease due to the 2011 deferral of 2010 costs related to storms and our cost reduction initiatives as allowed by the WVPSC.
  - A $27 million decrease due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - An $11 million gain from the sale of land in January 2011.

  These decreases were partially offset by:
  - A $54 million increase in demand side management, energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $41 million increase due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $35 million increase related to the 2011 recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the approved December 2011 Ohio stipulation agreement.
  - A $33 million increase in storm-related expenses.
  - A $33 million increase in plant outage and other plant operating and maintenance expenses.
  - A $25 million increase due to the 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
- **Asset Impairments and Other Related Charges** in 2011 included the following:
  - A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
  - A 2011 plant impairment of $42 million for the FGD project at Muskingum River Plant Unit 5.
  - A 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- **Depreciation and Amortization** expenses increased $15 million primarily due to the following:
  - A $23 million increase due to the amortization of carrying costs on deferred fuel as a result of the October 2011 Ohio POLR remand order.
  - A $20 million increase in depreciation and amortization for TCC primarily due to increased amortization of TCC's Securitized Transition Assets. This increase is partially offset by an increase in revenues within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $34 million decrease in depreciation and amortization for APCo primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia.
- **Interest and Investment Income** increased $20 million primarily due to interest income recorded in 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.

- **Carrying Costs Income** increased $323 million due to the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** increased $14 million primarily due to construction of the Turk and Dresden Plants and various environmental upgrades, partially offset by a decrease due to the completion of the Stall Unit in June 2010.
- **Interest Expense** decreased $56 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $71 million primarily due to an increase in pretax book income, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments.

TRANSMISSION OPERATIONS

Wholly-owned Entities

AEP Transmission Company, LLC (AEPTCo), a subsidiary of AEP, has seven wholly-owned transmission companies as follows:

AEP East Transmission Companies (all operating within PJM)

- AEP Appalachian Transmission Company, Inc. (APTCo) (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc. (IMTCo)
- AEP Kentucky Transmission Company, Inc. (KTCo)
- AEP Ohio Transmission Company, Inc. (OHTCo)
- AEP West Virginia Transmission Company, Inc. (WVTCo)

AEP West Transmission Companies (all operating within SPP)

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

IMTCo, OHTCo, OKTCo and WVTCo have been approved by the applicable state commissions or are operating where state approval was not necessary. APTCo has been authorized to submit projects for approval from the Virginia SCC. Applications for regulatory approvals have been filed and are currently under consideration in Arkansas, Kentucky and Louisiana.

The AEP East Transmission Companies and the AEP West Transmission Companies have FERC-approved returns on common equity of 11.49% and 11.20%, respectively, based on a capital structure of up to 50% equity. AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements.

All of the transmission companies' capital needs are provided by Parent, AEPTCo and/or the Utility Money Pool. The Utility Money Pool is used to meet the short-term borrowing needs of AEP regulated utility subsidiaries. The Utility Money Pool operates in accordance with the terms and conditions approved in regulatory orders.

In October 2012, AEPTCo completed a $250 million debt offering and immediately loaned $200 million and $50 million in proceeds to OHTCo and IMTCo, respectively. In December 2012, AEPTCo issued an additional $75 million in debt and immediately loaned the proceeds to OKTCo. AEPTCo will issue an additional $25 million in March 2013 but it is not yet determined which subsidiaries of AEPTCo will receive the proceeds.

Joint Venture Initiatives

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 Investment at December 31, 2012	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2022	MidAmerican Energy (50%) AEP (50%)	$ 3,056,000 (a)	$ 353,654	9.96 %
Prairie Wind	Kansas	2014	Westar Energy (50%) MidAmerican Energy (25%) (b) AEP (25%) (b)	180,000	7,091	12.8 %
Pioneer	Indiana	2018 (c)	Duke Energy (50%) AEP (50%)	950,000 (c)	1,876	12.54 %
RITELine IN	Indiana	2019	Exelon (12.5%) (d) AEP (87.5%) (d)	400,000	732 (e)	11.43 %
RITELine IL	Illinois	2019	Commonwealth Edison (75%) Exelon (12.5%) (d) AEP (12.5%) (d)	1,200,000	115 (e)	11.43 %
Transource Missouri	Missouri	2017	Great Plains Energy (13.5%) (f) AEP (86.5%) (f)	445,000	823	(g)%

(a) ETT's investment in current and future projects in ERCOT over the next ten years is expected to be $3.056 billion. Future projects will be evaluated on a case-by-case basis.
(b) AEP owns 25% of Prairie Wind Transmission, LLC (Prairie Wind) through its ownership interest in ETA. ETA is a 50/50 joint venture with MidAmerican Energy and AEP.
(c) The Pioneer project consists of approximately 240 miles of new 765 kV transmission lines, which is estimated to cost $950 million at completion. In August 2012, Pioneer announced it would develop the first 66-mile segment jointly with Northern Indiana Public Service Company at a total estimated cost of $330 million, subject to regulatory approval. The projected completion date for the first 66-mile segment is 2018. The projected completion dates for the remaining segments have not been determined.
(d) AEP owns 87.5% of RITELine Indiana, LLC (RITELine IN) through its ownership interest in RITELine Transmission Development, LLC (RTD) and AEP Transmission Holding Company, LLC (AEPTHC). AEP owns 12.5% of RITELine Illinois, LLC (RITELine IL) through its ownership interest in RTD. RTD is a 50/50 joint venture with Exelon Transmission Company, LLC and AEPTHC.
(e) RITELine IN is a consolidated variable interest entity. RTD received an order from the FERC in October 2011 granting incentives for the RITELine IN and RITELine IL projects. The projects are currently under evaluation by PJM.
(f) AEP owns 86.5% of Transource Missouri through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHC and Great Plains Energy formed to pursue competitive transmission projects in PJM, SPP and MISO. AEPTHC and Great Plains Energy own 86.5% and 13.5% of Transource, respectively.
(g) In August 2012, Transource Missouri requested at the FERC a base ROE of 10.6% plus incentives.

In August 2012, the PJM board cancelled the Potomac-Appalachian Transmission Highline Project (PATH Project), our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project. The FERC also set the issue of prudency of costs for settlement proceedings. AEP's investment in the PATH Project as of December 31, 2012 was $31 million.

For the consolidated entities within our Transmission Operations segment, we forecast approximately $700 million, excluding AFUDC, of construction expenditures for 2013. For the equity investments within our Transmission Operations segment, we forecast approximately $55 million of AEP equity contributions in 2013 to support construction expenditures and the payment of operating expenses.

2012 Compared to 2011

Income Before Extraordinary Item from our Transmission Operations segment increased from $30 million in 2011 to $43 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

2011 Compared to 2010

Income Before Extraordinary Item from our Transmission Operations segment increased from $9 million in 2010 to $30 million in 2011 primarily due to an increase in transmission investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

2012 Compared to 2011

Income Before Extraordinary Item from our AEP River Operations segment decreased from $45 million in 2011 to $15 million in 2012 primarily due to the 2012 drought, which had significant impacts on river conditions and crop yields, resulting in reduced grain exports.

2011 Compared to 2010

Income Before Extraordinary Item from our AEP River Operations segment increased from $37 million in 2010 to $45 million in 2011 primarily due to increased coal exports, increased barge fleet size and the cost reduction initiatives in 2010, partially offset by higher fuel, maintenance and flood-related expenses.

GENERATION AND MARKETING

2012 Compared to 2011

Income Before Extraordinary Item from our Generation and Marketing segment decreased from $14 million in 2011 to $7 million in 2012 primarily due to the expiration of wind-related production tax credits in 2011 and lower gross margins at the Oklaunion Plant, partially offset by higher retail margins in PJM and higher trading margins.

2011 Compared to 2010

Income Before Extraordinary Item from our Generation and Marketing segment decreased from $25 million in 2010 to $14 million in 2011 primarily due to lower gross margins at the Oklaunion Plant.

ALL OTHER

2012 Compared to 2011

Income Before Extraordinary Item from All Other decreased from a loss of $62 million in 2011 to a loss of $102 million in 2012 primarily due to costs associated with the early retirement of debt in 2012 and the 2012 adjustment of a UK windfall tax provision as a result of a recent related Supreme Court case, partially offset by a loss incurred in 2011 related to the settlement of litigation with BOA and Enron.

2011 Compared to 2010

Income Before Extraordinary Item from All Other decreased from a loss of $45 million in 2010 to a loss of $62 million in 2011 primarily due to a loss incurred in 2011 related to the settlement of litigation with BOA and Enron and a gain on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) in 2010, partially offset by a contribution to AEP's charitable foundation in 2010.

AEP SYSTEM INCOME TAXES

2012 Compared to 2011

Income Tax Expense decreased $214 million primarily due to a decrease in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron recorded in 2011, partially offset by the recording of federal and state income tax adjustments.

2011 Compared to 2010

Income Tax Expense increased $175 million primarily due to an increase in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2012		2011	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 17,757	52.3 %	$ 16,516	50.3 %
Short-term Debt	981	2.9	1,650	5.0
Total Debt	18,738	55.2	18,166	55.3
AEP Common Equity	15,237	44.8	14,664	44.7
Noncontrolling Interests	-	-	1	-
Total Debt and Equity Capitalization	$ 33,975	100.0 %	$ 32,831	100.0 %

Our ratio of debt-to-total capital decreased from 55.3% as of December 31, 2011 to 55.2% as of December 31, 2012 primarily due to an increase in common equity, partially offset by a net increase in debt issuances, including the March 2012 issuance of $800 million of securitization bonds.

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. As of December 31, 2012, we had $3.25 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization 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. As of December 31, 2012, our available liquidity was approximately $3.1 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	June 2015
Revolving Credit Facility	1,750	July 2016
Total	3,250	
Cash and Cash Equivalents	279	
Total Liquidity Sources	3,529	
Less: AEP Commercial Paper Outstanding	321	
Letters of Credit Issued	131	
Net Available Liquidity	$ 3,077	

We have credit facilities totaling $3.25 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.35 billion.

In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2012 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2012 was 0.44%.

Financing Plan

As of December 31, 2012, we have $2.2 billion of long-term debt due within one year which includes $528 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $363 million of securitization bonds and DCC Fuel notes payable which will be repaid. We plan to refinance the majority of our other maturities due within one year.

Securitized Accounts Receivables

In 2012, we renewed our receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2013 on or before its maturity.

Securitization of Regulatory Assets

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related securitization financing costs. APCo and WPCo are currently in settlement discussions with intervenors.

In August 2012, OPCo filed an application with the PUCO requesting securitization of the Deferred Asset Recovery Rider (DARR) balance. As of December 31, 2012, OPCo's DARR balance was $287 million, including $135 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018 by a non-bypassable rider. If the application is approved and the securitization bonds are issued, the DARR will cease and will be replaced by the Deferred Asset Phase-in Rider, which will recover the securitized asset over seven years.

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. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2012, this contractually-defined percentage was 51.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of December 31, 2012, 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. As of December 31, 2012, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.47 per share in January 2013. 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 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 do not believe restrictions related to our various financing arrangements 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,		
	2012	2011	2010
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 221	$ 294	$ 490
Net Cash Flows from Operating Activities	3,804	3,788	2,662
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

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,		
	2012	2011	2010
		(in millions)	
Net Income	$ 1,262	$ 1,949	$ 1,218
Depreciation and Amortization	1,782	1,655	1,641
Other	760	184	(197)
Net Cash Flows from Operating Activities	$ 3,804	$ 3,788	$ 2,662

Net Cash Flows from Operating Activities were $3.8 billion in 2012 consisting primarily of Net Income of $1.3 billion, $1.8 billion of noncash Depreciation and Amortization and $287 million in Asset Impairments related to certain Ohio generation assets. 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. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act and an increase in tax versus book temporary differences from operations. During 2012, we also contributed $200 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $3.8 billion in 2011 consisting primarily of Net Income of $1.9 billion and $1.7 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. Following a Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance and the PUCT's approval of a stipulation agreement, we recorded an Extraordinary Item, Net of Tax of $373 million for the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts and the reversal of tax related regulatory credits. We also recorded $393 million in Carrying Costs Income primarily related to the Texas restructuring appeals. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. During 2011, we also contributed $450 million to our qualified pension trust.

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.

Investing Activities

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Construction Expenditures	$ (3,025)	$ (2,669)	$ (2,345)
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisitions of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other	(183)	(5)	(119)
Net Cash Flows Used for Investing Activities	$ (3,391)	$ (2,890)	$ (2,523)

Net Cash Flows Used for Investing Activities were $3.4 billion in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for $70 million.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

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.

Financing Activities

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Issuance of Common Stock, Net	$ 83	$ 92	$ 93
Issuance/Retirement of Debt, Net	544	(33)	497
Retirement of Cumulative Preferred Stock	-	(64)	-
Dividends Paid on Common Stock	(916)	(898)	(824)
Other	(66)	(68)	(101)
Net Cash Flows Used for Financing Activities	$ (355)	$ (971)	$ (335)

Net Cash Flows Used for Financing Activities in 2012 were $355 million. Our net debt issuances were $544 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $800 million of securitization bonds, $287 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $902 million of senior unsecured and other debt notes, $315 million of junior subordinate debentures, $220 million of pollution control bonds, $206 million of securitization bonds and a decrease in short-term borrowing of $669 million. We paid common stock dividends of $916 million. See Note 13 – Financing Activities.

Net Cash Flows Used for Financing Activities in 2011 were $971 million. Our net debt retirements were $33 million. The net retirements included retirements of $727 million of senior unsecured and other debt notes, $778 million of pollution control bonds and $159 million of securitization bonds offset by issuances of $710 million of notes, $627 million of pollution control bonds and an increase in short-term borrowing of $304 million. We paid common stock dividends of $898 million and $64 million to retire all of our subsidiaries' preferred stocks.

Net Cash Flows Used for Financing Activities in 2010 were $335 million. 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.

The following financing activities occurred during 2012:

AEP Common Stock:

- During 2012, we issued 2.2 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $83 million.

Debt:

- During 2012, we issued approximately $2.9 billion of long-term debt, including $1.7 billion of senior notes at interest rates ranging from 1.65% to 4.78% and $800 million of securitization bonds at interest rates ranging from 0.88% to 2.85%. We also issued $65 million of pollution control revenue bonds at 2.25%, $65 million of notes payable at 4.58% and $220 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2012, we entered into $750 million of interest rate derivatives and settled $458 million of such transactions. The settlements resulted in net cash payments of $23 million. As of December 31, 2012, we had in place $1.2 billion of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2013:

- In January 2013, TCC retired $105 million of its outstanding Securitization Bonds.
- In January and February 2013, I&M retired $23 million of Notes Payable related to DCC Fuel.
- In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.6 billion of construction expenditures excluding equity AFUDC and capitalized interest for 2013. For 2014 and 2015, we forecast construction expenditures of $3.8 billion each year. 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 2013 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2013 Budgeted Construction Expenditures
	(in millions)
Environmental	$ 544
Generation	647
Transmission	1,286
Distribution	1,009
Other	92
Total	$ 3,578

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including 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 that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements.

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 AEGCo and I&M are $739 million and $739 million, respectively, as of December 31, 2012.

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 12. 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 $29 million for the remaining railcars as of December 31, 2012. 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. As of December 31, 2012, the maximum potential loss was approximately $25 million 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 balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations as of December 31, 2012:

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)	$ 981	$ -	$ -	$ -	$ 981
Interest on Fixed Rate Portion of Long-term Debt (b)	861	1,527	1,308	6,011	9,707
Fixed Rate Portion of Long-term Debt (c)	1,410	2,425	2,493	10,513	16,841
Variable Rate Portion of Long-term Debt (d)	761	182	2	-	945
Capital Lease Obligations (e)	95	144	122	244	605
Noncancelable Operating Leases (e)	302	532	452	1,034	2,320
Fuel Purchase Contracts (f)	2,631	3,971	2,906	3,097	12,605
Energy and Capacity Purchase Contracts (g)	177	359	368	2,494	3,398
Construction Contracts for Capital Assets (h)	859	1,264	1,197	1,326	4,646
Total	$ 8,077	$ 10,404	$ 8,848	$ 24,719	$ 52,048

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See “Long-term Debt” section of Note 13. Represents principal only excluding interest.
(d) See “Long-term Debt” section of Note 13. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.11% and 2.18% as of December 31, 2012.
(e) See Note 12.
(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 $61 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, 2012, we expect to make contributions to our pension plans totaling $108 million in 2013. Estimated contributions of $107 million in 2014 and $107 million in 2015 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 90.2% funded as of December 31, 2012.

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. As of December 31, 2012, 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)	$ 131	$ -	$ -	$ -	$ 131
Guarantees of the Performance of Outside Parties (b)	-	-	-	115	115
Guarantees of Our Performance (c)	604	15	10	62	691
Total Commercial Commitments	$ 735	$ 15	$ 10	$ 177	$ 937

(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 and debt service reserves. 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 $131 million with maturities ranging from January 2013 to April 2014. See "Letters of Credit" section of Note 5.
(b) See "Guarantees of Third-Party Obligations" section of Note 5.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

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. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one-year extension of the 50% bonus depreciation to 2013.

The enacted provisions had no material impact on net income, financial condition or cash flows in 2012, but are expected to result in material future cash flow benefits.

CYBER SECURITY

Cyber security presents a heightened risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to our system are potentially disruptive to people, property and commerce and create risk for our business, our investors and our customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefine how the government interfaces with critical infrastructure, such as the electric grid. We already operate under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that will be developed through this executive order will be reviewed by the FERC. We expect to participate in the process and will share best practices already in place. We protect our critical cyber assets, such as our data centers and transmission operations centers and business network, using multiple layers of cyber security and authentication. We constantly scan the system for risks or threats.

Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, we continually assess our own cyber security tools and processes to determine where we might need to strengthen our defenses.

In recent years, we have taken several steps to enhance our capabilities for identifying risks or threats. AEP became the first utility in the country to build a Cyber Security Operations Center. Funding was included as part of a larger American Recovery and Reinvestment Act Department of Energy Smart Grid Demonstration Project grant. This facility is designed as a pilot cyber threat and information-sharing center specifically for the electric sector.

We have partnered with a nonaffiliated entity to leverage their experience and technical capabilities, which were developed through their work with the U.S. Department of Defense. We work with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other and with the Department of Homeland Security. We also worked with a nonaffiliated entity to conduct several seminars in 2011 about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect AEP while helping our industry advance its cyber security capabilities.

In March 2012, we signed a cooperative research and development agreement with the Department of Homeland Security's Office of Cyber Security and Communications, further enhancing our ability to directly exchange information about cyber threats. In addition, we continue to partner with a number of federal and industry groups to advance the national capabilities of cyber security. Among them is the U.S. Department of Energy, where we are working on several pilot projects covering advanced cyber security and assessment tools.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND 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 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 disclosures relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our 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 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 expense and income recognition with regulated revenues. 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. Similarly, we record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability 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 as well as the return of revenues, 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 or establishment of a regulatory liability 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 4 for further detail related to regulatory assets and regulatory 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 for our Utility Operations segment were $5 million, $(81) million and $46 million for the years ended December 31, 2012, 2011 and 2010, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Utility Operations segment were $473 million and $468 million as of December 31, 2012 and 2011, respectively.

In March 2012, our Generation and Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation and Marketing segment was $31 million for the year ended December 31, 2012. Accrued unbilled revenues for the Generation and Marketing segment were $38 million as of December 31, 2012.

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 primarily 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 9 and 10. 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 including planned abandonments and a probable disallowance for rate-making on a plant under construction 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. 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. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of 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. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions of the use of the asset. We perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. 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 for 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 health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as 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 7 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	**2012**	**2011**	**2010**
		(in millions)	
Pension Plans	$ 134	$ 118	$ 141
Postretirement Plans	89	73	111

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 2013, 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 and changes in tax rates which affect a portion of the Postretirement Plans' assets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 6.5% for the Qualified Plan and 7% 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	
	2013 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2013 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	40 %	9.00 %	66 %	8.60 %
Fixed Income	50 %	4.00 %	33 %	3.50 %
Other Investments	10 %	8.80 %	-%	- %
Cash and Cash Equivalents	-%	-%	1 %	1.50 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6.5% and 7% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 13.8% and 8.1% for the years ended December 31, 2012 and 2011, respectively. The Postretirement Plans' assets had an actual gain of 15.4% and 0.4% for the years ended December 31, 2012 and 2011, 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, 2012, we had cumulative gains of approximately $302 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains 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 is constructed with cash flows 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 as of December 31, 2012 under this method was 3.95% for the Qualified Plan, 3.8% for the Nonqualified Plans and 3.95% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans' assets of 6.5%, discount rates of 3.95% and 3.8% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $175 million, $131 million and $102 million in 2013, 2014 and 2015, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7%, a discount rate of 3.95% and various other assumptions, we estimate credits will approximate $15 million, $19 million and $25 million in 2013, 2014 and 2015, 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.

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical costs will be capped reducing our future exposure to medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. This change will reduce costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous paragraph.

The value of the Pension Plans' assets increased to $4.7 billion as of December 31, 2012 from $4.3 billion as of December 31, 2011 primarily due to investment returns and $200 million of company contributions. During 2012, the Qualified Plan paid $367 million and the Nonqualified Plans paid $16 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.6 billion as of December 31, 2012 from $1.4 billion as of December 31, 2011 primarily due to investment returns and contributions by the company and the participants. The Postretirement Plans paid $151 million in benefits to plan participants during 2012.

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
- Compensation increase rate
- 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, 2012 Benefit Obligations				
Discount Rate	$ (272)	$ 300	$ (105)	$ 116
Compensation Increase Rate	12	(11)	NA	NA
Cash Balance Crediting Rate	39	(35)	NA	NA
Health Care Cost Trend Rate	NA	NA	42	(53)
Effect on 2012 Periodic Cost				
Discount Rate	(17)	18	(11)	12
Compensation Increase Rate	4	(4)	NA	NA
Cash Balance Crediting Rate	11	(10)	NA	NA
Health Care Cost Trend Rate	NA	NA	19	(17)
Expected Return on Plan Assets	(22)	22	(7)	7

NA Not applicable.

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, financial instruments, leases, insurance, hedge accounting and consolidation policy. 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 RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and through its transactions 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 as we occasionally 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 conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail 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.

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 power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk 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 and Finance groups in accordance with our established risk management policies as 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 Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, 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, 2011:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2012

	Utility Operations	Generation and Marketing	Total
		(in millions)	
Total MTM Risk Management Contract Net Assets as of December 31, 2011	$ 59	$ 132	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	-	(2)	(2)
Fair Value of New Contracts at Inception When Entered During the Period (a)	5	18	23
Acquisition of Supply Contracts (b)	-	(25)	(25)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	3	5	8
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	1	-	1
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 68	$ 128	196
Commodity Cash Flow Hedge Contracts			(12)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(37)
Collateral Deposits			43
Total MTM Derivative Contract Net Assets as of December 31, 2012			$ 190

(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 liabilities associated with the initial fair value of supply contracts from the BlueStar acquisition in March 2012.
(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 statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 9 – Derivatives and Hedging and Note 10 – 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, 2012, our credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2012, 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	$ 643	$ -	$ 643	2	$ 267
Split Rating	3	2	1	1	1
Noninvestment Grade	1	1	-	-	-
No External Ratings:					
Internal Investment Grade	98	-	98	3	36
Internal Noninvestment Grade	62	10	52	1	34
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338
Total as of December 31, 2011	$ 960	$ 19	$ 941	5	$ 348

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, 2012, a near term typical change in commodity prices is not expected to materially impact 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, 2012				Twelve Months Ended December 31, 2011			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 2	$ -	$ -

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, 2012 and 2011, the estimated EaR on our debt portfolio for the following twelve months was $42 million and $29 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, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

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, 2012, 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 26, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

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, 2012, 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, 2012, 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, 2012 of the Company and our report dated February 26, 2013 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

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, 2012. 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, 2012.

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.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2012	**2011**	**2010**
REVENUES			
Utility Operations	$ 13,677	$ 14,091	$ 13,687
Other Revenues	1,268	1,025	740
TOTAL REVENUES	14,945	15,116	14,427
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,111	4,421	4,029
Purchased Electricity for Resale	1,169	1,191	1,000
Other Operation	2,962	2,868	3,132
Maintenance	1,115	1,236	1,142
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,782	1,655	1,641
Taxes Other Than Income Taxes	850	824	820
TOTAL EXPENSES	12,289	12,334	11,764
OPERATING INCOME	2,656	2,782	2,663
Other Income (Expense):			
Interest and Investment Income	8	27	38
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	93	98	77
Interest Expense	(988)	(933)	(999)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,822	2,367	1,849
Income Tax Expense	604	818	643
Equity Earnings of Unconsolidated Subsidiaries	44	27	12
INCOME BEFORE EXTRAORDINARY ITEM	1,262	1,576	1,218
EXTRAORDINARY ITEM, NET OF TAX	-	373	-
NET INCOME	1,262	1,949	1,218
Net Income Attributable to Noncontrolling Interests	3	3	4
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,682,469	482,169,282	479,373,306
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	485,084,694	482,460,328	479,601,442
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
CASH DIVIDENDS DECLARED PER SHARE	$ 1.88	$ 1.85	$ 1.71

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31, 2012	2011	2010
Net Income	$ 1,262	$ 1,949	$ 1,218
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $18 and $14 in 2012, 2011 and 2010, Respectively	(15)	(34)	26
Securities Available for Sale, Net of Tax of $1, $1 and $4 in 2012, 2011 and 2010, Respectively	2	(2)	(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $16, $13 and $12 in 2012, 2011 and 2010, Respectively	31	24	22
Pension and OPEB Funded Status, Net of Tax of $62, $41 and $25 in 2012, 2011 and 2010, Respectively	115	(77)	(47)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	133	(89)	(7)
TOTAL COMPREHENSIVE INCOME	1,395	1,860	1,211
Total Comprehensive Income Attributable to Noncontrolling Interests	3	3	4
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,392	1,857	1,207
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,392	$ 1,852	$ 1,204

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	AEP Common Shareholders						
	Common Stock				Accumulated Other Comprehensive Income (Loss)		
	Shares	Amount	Paid-in Capital	Retained Earnings		Noncontrolling Interests	Total
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
Net Income				1,214		4	1,218
Other Comprehensive Loss					(7)		(7)
TOTAL EQUITY – DECEMBER 31, 2010	501	3,257	5,904	4,842	(381)	-	13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
Subtotal – Equity							12,805
Net Income				1,946		3	1,949
Other Comprehensive Loss					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	3,274	5,970	5,890	(470)	1	14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Subtotal – Equity							13,842
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	$ 3,289	$ 6,049	$ 6,236	$ (337)	$ -	$ 15,237

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in millions)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 279	$ 221
Other Temporary Investments (December 31, 2012 and 2011 Amounts Include $311 and $281, Respectively, Related to Transition Funding and EIS)	324	294
Accounts Receivable:		
Customers	685	690
Accrued Unbilled Revenues	195	106
Pledged Accounts Receivable - AEP Credit	856	920
Miscellaneous	171	150
Allowance for Uncollectible Accounts	(36)	(32)
Total Accounts Receivable	1,871	1,834
Fuel	844	657
Materials and Supplies	675	635
Risk Management Assets	191	193
Regulatory Asset for Under-Recovered Fuel Costs	88	65
Margin Deposits	76	67
Prepayments and Other Current Assets	241	216
TOTAL CURRENT ASSETS	4,589	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,279	24,938
Transmission	9,846	9,048
Distribution	15,565	14,783
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,945	3,780
Construction Work in Progress	1,819	3,121
Total Property, Plant and Equipment	57,454	55,670
Accumulated Depreciation and Amortization	18,691	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	38,763	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,106	6,026
Securitized Transition Assets	2,117	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,706	1,592
Goodwill	91	76
Long-term Risk Management Assets	368	403
Deferred Charges and Other Noncurrent Assets	1,627	1,346
TOTAL OTHER NONCURRENT ASSETS	11,015	11,070
TOTAL ASSETS	$ 54,367	$ 52,223

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2012 and 2011
(dollars in millions)

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts Payable	$ 1,169	$ 1,095
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	657	666
Other Short-term Debt	324	984
Total Short-term Debt	981	1,650
Long-term Debt Due Within One Year (December 31, 2012 and 2011 Amounts Include $367 and $293, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	2,171	1,433
Risk Management Liabilities	155	150
Customer Deposits	316	289
Accrued Taxes	747	717
Accrued Interest	269	279
Regulatory Liability for Over-Recovered Fuel Costs	47	8
Other Current Liabilities	968	990
TOTAL CURRENT LIABILITIES	6,823	6,611
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2012 and 2011 Amounts Include $2,227 and $1,674, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	15,586	15,083
Long-term Risk Management Liabilities	214	195
Deferred Income Taxes	9,252	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,544	3,195
Asset Retirement Obligations	1,696	1,472
Employee Benefits and Pension Obligations	1,075	1,801
Deferred Credits and Other Noncurrent Liabilities	940	974
TOTAL NONCURRENT LIABILITIES	32,307	30,947
TOTAL LIABILITIES	39,130	37,558
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2012	2011
Shares Authorized	600,000,000	600,000,000
Shares Issued	506,004,962	503,759,460

	2012	2011
(20,336,592 Shares were Held in Treasury as of December 31, 2012 and 2011)	3,289	3,274
Paid-in Capital	6,049	5,970
Retained Earnings	6,236	5,890
Accumulated Other Comprehensive Income (Loss)	(337)	(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	15,237	14,664
Noncontrolling Interests	-	1
TOTAL EQUITY	15,237	14,665
TOTAL LIABILITIES AND EQUITY	$ 54,367	$ 52,223

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 1,262	$ 1,949	$ 1,218
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,782	1,655	1,641
Deferred Income Taxes	636	794	809
Gain on Settlement with BOA and Enron	-	(51)	-
Settlement of Litigation with BOA and Enron	-	(211)	-
Extraordinary Item, Net of Tax	-	(373)	-
Asset Impairments and Other Related Charges	300	139	-
Carrying Costs Income	(53)	(393)	(70)
Allowance for Equity Funds Used During Construction	(93)	(98)	(77)
Mark-to-Market of Risk Management Contracts	57	37	30
Amortization of Nuclear Fuel	136	137	139
Pension Contributions to Qualified Plan Trust	(200)	(450)	(500)
Property Taxes	(19)	(15)	(21)
Fuel Over/Under-Recovery, Net	157	(25)	(253)
Change in Other Noncurrent Assets	(236)	(112)	(89)
Change in Other Noncurrent Liabilities	127	307	202
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(16)	107	(866)
Fuel, Materials and Supplies	(224)	176	221
Accounts Payable	(60)	(44)	(36)
Accrued Taxes, Net	174	193	179
Other Current Assets	(3)	37	73
Other Current Liabilities	77	29	62
Net Cash Flows from Operating Activities	3,804	3,788	2,662
INVESTING ACTIVITIES			
Construction Expenditures	(3,025)	(2,669)	(2,345)
Change in Other Temporary Investments, Net	(27)	8	(4)
Purchases of Investment Securities	(1,047)	(1,321)	(1,918)
Sales of Investment Securities	988	1,379	1,817
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisition of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other Investing Activities	(97)	(71)	(14)
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	83	92	93
Issuance of Long-term Debt	2,856	1,328	1,270
Commercial Paper and Credit Facility Borrowings	25	488	565
Change in Short-term Debt, Net	(654)	744	770
Retirement of Long-term Debt	(1,643)	(1,665)	(1,993)
Retirement of Cumulative Preferred Stock	-	(64)	-
Commercial Paper and Credit Facility Repayments	(40)	(928)	(115)
Principal Payments for Capital Lease Obligations	(71)	(71)	(95)
Dividends Paid on Common Stock	(916)	(898)	(824)
Dividends Paid on Cumulative Preferred Stock	-	(2)	(3)
Other Financing Activities	5	5	(3)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at Beginning of Period	221	294	490
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

See Notes to Consolidated Financial Statements beginning on page 54.

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

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business is the generation, transmission and distribution of electric power. The subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and 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 provide electric supply for residential, commercial and industrial customers in Ohio, Illinois and other deregulated electricity markets and also provide energy management solutions throughout the United States, including energy efficiency services through our independent retail electric supplier.

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

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. Wholesale power transactions 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 the FERC's finding that PSO and SWEPCo have 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. The state regulatory commissions 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 Texas Retail Electric Providers (REPs). Through our nonregulated subsidiaries, we enter 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. We have no active REPs in ERCOT.

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. 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. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are based on formula rates included in the PJM OATT that are cost-based. Although TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for our seven wholly-owned transmission subsidiaries within our Transmission Operations segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

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. In October 2012, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and the AEP System Interim Allowance Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision is expected from the FERC in mid-2013.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and 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 the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the 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 the statements of income and our proportionate share of the assets and liabilities are reflected on the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our 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 (deferred revenue reductions or refunds) 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. 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 Texas for TNC. OPCo applies "Regulated Operations" accounting treatment only to specifically approved portions of its generation business consisting of fuel and capacity costs.

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

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 10.

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 the 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 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.

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, and for those balances less than 120 days where the collection is doubtful. 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

In regulated jurisdictions including Ohio through December 31, 2014, 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. In Ohio, we record allowances expected to be consumed subsequent to December 31, 2014 at the lower of cost or market when our allowances are no longer included in the FAC due to energy auctions of SSO load. 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 the balance sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on the statements of income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on the 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 the 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 cost. Additions, major replacements and betterments are added to the plant accounts. 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 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. 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." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. 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 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 owned by OPCo and certain generating assets in Arkansas and 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, Accounts Payable and Short-term Debt 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 and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. Our market risk oversight staff independently monitors our valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

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 nonbinding 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. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

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 trusts.

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. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. 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 primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

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. 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. 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.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through the ESP related to non-auction standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas 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, changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our 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 the 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.

Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the 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 the 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 the statements of income. Other RTOs in which we participate 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 the 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 the 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, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. 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 unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on the statements of income on a net basis. In jurisdictions subject to cost-based regulation, we defer 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 the 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 the 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 the 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 9.

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 accordance with regulatory orders, 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. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

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 expense.

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

For APCo's commercial scale carbon capture and sequestration facility at the Mountaineer Plant and OPCo's gridSMART® demonstration program, APCo and OPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. In addition, AEP built a cyber security operations center that will be used to enhance the capabilities for identifying cyber risks or threats, which was also partially funded by the gridSMART® demonstration grant for OPCo's incurred costs. These reimbursements result in the reduction of Other Operation and Maintenance expenses on the statements of income or a reduction in Construction Work in Progress on the balance sheets.

Debt

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 the 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 net amortization expense in Interest Expense on the statements of income.

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 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 allocations and periodically rebalance the investments to targeted allocations 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 optimize 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 investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	40.0 %
Fixed Income	50.0 %
Other Investments	10.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

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.
- No individual stock may be more 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 any single issuer
- 5% for private placements
- 5% for 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 multiple 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 the 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 SNF 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 5 for additional discussion of nuclear matters. See “Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal” section of Note 10 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).

Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in our equity section. Our components of AOCI as of December 31, 2012 and 2011 are shown in the following table:

Components	December 31, 2012	December 31, 2011
	(in millions)	
Cash Flow Hedges, Net of Tax	$ (38)	$ (23)
Securities Available for Sale, Net of Tax	4	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax	112	81
Pension and OPEB Funded Status, Net of Tax	(415)	(530)
Total	$ (337)	$ (470)

Stock-Based Compensation Plans

As of December 31, 2012, we had stock options, performance units 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 Human Resources 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 the statements of income for the years ended December 31, 2012, 2011 and 2010 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, 2012, 2011 and 2010, 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 14 for additional discussion.

Earnings Per Share (EPS)

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

Amounts Attributable to AEP Common Shareholders	Years Ended December 31, 2012	2011	2010
		(in millions)	
Income Before Extraordinary Item	$ 1,259	$ 1,568	$ 1,211
Extraordinary Item, Net of Tax	-	373	-
Net Income	$ 1,259	$ 1,941	$ 1,211

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 the statements of income:

	Years Ended December 31, 2012		2011		2010	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,259		$ 1,941		$ 1,211	
Weighted Average Number of Basic Shares Outstanding	484.7	$ 2.60	482.2	$ 4.02	479.4	$ 2.53
Weighted Average Dilutive Effect of:						
Performance Share Units	-	-	-	-	0.1	-
Stock Options	-	-	0.1	-	-	-
Restricted Stock Units	0.4	-	0.2	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	485.1	$ 2.60	482.5	$ 4.02	479.6	$ 2.53

Options to purchase 136,250 shares of common stock as of December 31, 2010 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. There were no antidilutive shares outstanding as of December 31, 2012 and 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, OPCo impaired certain generating units, including those discussed above (see Note 6). As a result of this impairment of the full book value of these assets, OPCo ceased depreciation on these generating units effective December 1, 2012.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2012, AEP's ownership and investment in OVEC were 43.47% and $4.4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generating plants. As of December 31, 2012, OVEC completed financing of $1.4 billion required for these environmental projects through debt issuances. As of December 31, 2012, one plant was operating with new environmental controls and the other plant is scheduled to be operational with new environmental controls during the second quarter of 2013.

The following details related party transactions for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
Related Party Transactions	**2012**	**2011**	**2010**
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
OVEC	$ -	$ -	$ (20)(a)
AEP Consolidated Revenues – Other Revenues:			
OVEC – Barging and Other Transportation Services	30	37	29
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	273	383 (b)	302 (b)

(a) The parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales through an agreement that began in January 2010 and ended in June 2010.

(b) The parties to the Interconnection Agreement purchased power from OVEC to serve retail sales in 2011 and 2010. The total amount reported in 2011 and 2010 includes $66 million and $10 million, respectively, related to these agreements.

Supplementary Cash Flow Information

	Years Ended December 31,		
Cash Flow Information	**2012**	**2011**	**2010**
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 931	$ 900	$ 958
Income Taxes	(82)	(118)	(268)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	63	54	225
Construction Expenditures Included in Current Liabilities as of December 31,	439	380	267
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	35	1	-
Assumption of Liabilities Related to Acquisitions	56	-	-
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	30	-	-

2. EXTRAORDINARY ITEM

TCC Texas Restructuring

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

Following a remand proceeding, the PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. Based upon the PUCT order, TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

3. 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.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2012, OPCo's net deferred fuel balance was $519 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another similar project by the end of 2013.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo.

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

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved an ESP modified stipulation which established a SSO pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates. Those rates remained in effect until the new ESP was approved in August 2012. See the "June 2012 – May 2015 ESP Including Capacity Charge" section below.

As a result of the PUCO's rejection of the modified stipulation, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in 2011.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the deferred fuel balance in accordance with the 2009 - 2011 ESP order. OPCo also filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. See the "2009 – 2011 ESP" section above. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015, adopted a 12% earnings threshold for the SEET and allowed the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo’s collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss the IEU’s action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition. A decision from the Supreme Court of Ohio is pending.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo’s generation assets including the transfer of OPCo’s generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and Ohio Consumers’ Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, filings at the FERC were submitted related to corporate separation. See the “Corporate Separation and Termination of Interconnection Agreement” section below under FERC Rate Matters. Our results of operations related to generation in Ohio will be largely determined by prevailing market conditions.

2011 Ohio Distribution Base Rate Case

In December 2011, the PUCO approved a stipulation which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved in December 2011 by the modified stipulation in the ESP proceeding. However, when the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as part of the June 2012 – May 2015 ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. If the PUCO extends recovery beyond twelve months and/or does not commence cost recovery by April 2013, OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of December 31, 2012, OPCo recorded $62 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $36 million, including $19 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

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 filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings totaling $27 million to be paid in equal monthly installment over the period January 2014 to May 2015 without interest. In the event Ormet does not pay the $27 million, the PUCO permitted OPCo to recover the unpaid balance, up to $20 million, in the economic development rider. To the extent unpaid amounts exceed $20 million, it will reduce future net income and cash flows.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. As of December 31, 2012, excluding costs attributable to its joint owners and a $62 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.7 billion of expenditures, including AFUDC and capitalized interest of $328 million and related transmission costs of $120 million.

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. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market.

The PUCT approved 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 (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and TIEC filed petitions for review at the Supreme Court of Texas. The Supreme Court of Texas has requested full briefing from the parties.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operations and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates.

In December 2012, several intervenors, including the PUCT staff, filed testimony that recommended an annual base rate increase between $16 million and $51 million based upon a return on common equity between 9.0% and 9.55%. In addition, two intervenors recommended that the Turk Plant be excluded from rate base. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it would reduce future net income and cash flows and impact financial condition.

Louisiana 2012 Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

APCo and WPCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of average annual generating capacity presently owned by OPCo. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Virginia Fuel Filing

In April 2012, APCo filed an application with the Virginia SCC for an annual increase in fuel revenues of $117 million to be effective June 2012. The filing included forecasted costs for the 15-month period ended August 2013 and requested recovery of APCo's anticipated unrecovered fuel balance as of May 2012 over a two-year period commencing in June 2012. The non-incremental portion of APCo's forecasted and deferred wind purchased power costs were reflected in APCo's filing. In June 2012, the Virginia SCC approved the application as filed.

Environmental Rate Adjustment Clause (Environmental RAC)

In November 2011, the Virginia SCC issued an order which approved APCo’s Environmental RAC recovery of $30 million to be collected over one year beginning in February 2012 but denied recovery of certain environmental costs. As a result, in 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. APCo appealed the Virginia SCC decision to the Supreme Court of Virginia. In November 2012, the Supreme Court of Virginia issued an order which allowed APCo to recover an additional $6 million of 2009 and 2010 actual Environmental RAC costs and affirmed the portion of the November 2011 order that denied recovery of certain environmental costs. The Virginia SCC issued an order in December 2012 which permitted APCo to extend the current Environmental RAC surcharge for the months of February and March 2013 in order to collect the $6 million.

Generation Rate Adjustment Clause (Generation RAC)

In January 2012, the Virginia SCC issued a Generation RAC order which allowed APCo to recover $26 million annually, effective March 2012, related to recovery of the Dresden Plant. APCo filed with the Virginia SCC to continue the current Generation RAC rate to recover costs of the Dresden Plant through February 2014. In December 2012, the Virginia SCC granted APCo’s application as filed and required APCo to submit a new Generation RAC filing in March 2013.

APCo IGCC Plant

As of December 31, 2012, 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. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

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

In March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. Also in March 2012, APCo and WPCo filed their ENEC application with the WVPSC for the fourth year of a four-year phase-in plan which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral and other ENEC-related assets. If the financing order is not issued, APCo and WPCo requested that recovery of these costs be allowed in current rates.

In July 2012, the WVPSC issued an order that approved a settlement agreement which recommended no change in total ENEC rates but reflected a $24 million increase in the construction surcharge and a $24 million decrease in ENEC rates. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize a total of $422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of $13 million and related future financing costs of $7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo’s and WPCo’s request and the intervenors’ testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related future securitization financing costs. As of December 31, 2012, APCo’s ENEC under-recovery balance of $299 million, net of 2012 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding $4 million of unrecognized equity carrying costs and $12 million of other ENEC-related assets. APCo and WPCo are currently in settlement discussions with intervenors.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In 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 October 2012, the OCC issued a final order that found PSO's fuel and purchased power costs were prudently incurred without any disallowance and that PSO's shareholder's portion of off-system sales margins would remain at 25%.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, testimony filed by the OCC staff and the Oklahoma Office of the Attorney General generally agreed with PSO's plan, although they recommended no earnings component on the PPA and to delay final decisions on parts of the plan including cost recovery of NES Unit 3 and any increases in fuel costs due to reductions in the output of energy from NES Unit 3 beginning in 2021. The testimony recommended that cost recovery could extend past 2026 on parts of the plan and recommended a $175 million cost cap on NES Unit 3 environmental investment.

Also, an intervenor representing some of PSO's large industrial users opposed virtually all of PSO's plan, including recommending no cost recovery of NES Units 3 and 4 book value amounts not recovered at the time of their retirement and no recovery of the PPA costs, including earnings on the PPA. A hearing is scheduled for April 2013.

I&M Rate Matters

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015 and supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, we have incurred $71 million related to these environmental controls, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows.

In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. Under the terms of the NSR consent decree modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028.

KPCo Rate Matters

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by OPCo. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. In addition, KPCo announced its plan to retire Big Sandy Plant, Unit 2 in early 2015, subject to regulatory approval, and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

Big Sandy Plant, Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Plant, Unit 2 with a dry FGD system. As part of the Mitchell Plant transfer filing discussed above, KPCo requested costs related to the FGD project be established as a regulatory asset and recovered in KPCo's next base rate case. As of December 31, 2012, KPCo has incurred $29 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet. If KPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and 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. In 2006, a FERC Administrative Law Judge 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.

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 supported AEP's position and required a compliance filing. In August 2010, the affected companies, including the AEP East Companies, filed a compliance filing with the FERC. The AEP East Companies provided reserves for net refunds for SECA settlements. The AEP East Companies settled with various parties prior to the FERC compliance filing and entered into additional settlements subsequent to the compliance filing being filed at the FERC. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, management believes that the reserve is adequate to pay the refunds, including interest, and any remaining exposure beyond the reserve is immaterial.

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement among APCo, I&M and KPCo. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

Similar filings have been made at the KPSC, the Virginia SCC and the WVPSC. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

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4. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 86	$ 56	1 year
Under-recovered Fuel Costs - does not earn a return	2	9	1 year
Total Current Regulatory Assets	$ 88	$ 65	
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			
Storm Related Costs	$ 23	$ 24	
Economic Development Rider	13	13	
Other Regulatory Assets Not Yet Being Recovered	1	-	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	172	10	
Virginia Environmental Rate Adjustment Clause	29	18	
Mountaineer Carbon Capture and Storage Product Validation Facility	14	14	
Litigation Settlement	11	11	
Deferred Wind Power Costs	5	38	
Special Rate Mechanism for Century Aluminum	-	13	
Other Regulatory Assets Not Yet Being Recovered	36	14	
Total Regulatory Assets Not Yet Being Recovered	304	155	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	519	521	6 years
West Virginia Expanded Net Energy Charge	273	327	(a)
Ohio Deferred Asset Recovery Rider	152	173	6 years
Unamortized Loss on Reacquired Debt	82	92	31 years
Ohio Capacity Deferral	66	-	6 years
Transmission Cost Recovery Rider	49	28	3 years
Meter Replacement Costs	47	39	10 years
Storm Related Costs	36	65	6 years
RTO Formation/Integration Costs	15	18	7 years
Red Rock Generating Facility	10	10	44 years
Economic Development Rider	5	12	1 year
Capacity Auction True-Up	-	692	
Other Regulatory Assets Being Recovered	10	15	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,896	2,308	12 years
Income Taxes, Net	1,353	1,237	44 years
Postemployment Benefits	45	47	5 years
Virginia Transmission Rate Adjustment Clause	33	20	2 years
Cook Nuclear Plant Refueling Outage Levelization	27	41	3 years
Storm Related Costs	27	35	6 years
West Virginia Expanded Net Energy Charge	26	32	(a)
Distribution Decoupling	16	-	2 years
Deferred Restructuring Costs	15	18	6 years
Deferred PJM Fees	14	22	2 years
Vegetation Management	13	11	1 year
Peak Demand Reduction/Energy Efficiency	12	8	1 year
Asset Retirement Obligation	9	14	8 years
Virginia Environmental Rate Adjustment Clause	8	24	1 year
Unrealized Loss on Forward Commitments	8	16	2 years
Restructuring Transition Costs	5	8	4 years
Other Regulatory Assets Being Recovered	31	38	various
Total Regulatory Assets Being Recovered	4,802	5,871	
Total Noncurrent Regulatory Assets	$ 5,106	$ 6,026	

(a) Request for securitization is pending from the WVPSC to recover $422 million as securitized transition assets from ratepayers over the securitization bond period.

Regulatory liabilities are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 25	$ 5	1 year
Over-recovered Fuel Costs - does not pay a return	22	3	1 year
Total Current Regulatory Liabilities	$ 47	$ 8	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Louisiana Refundable Construction Financing Costs	$ 96	$ 53	
Other Regulatory Liabilities Not Yet Being Paid	4	5	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	9	8	
Total Regulatory Liabilities Not Yet Being Paid	109	66	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,511	2,270	(a)
Advanced Metering Infrastructure Surcharge	83	78	8 years
Deferred Investment Tax Credits	23	27	48 years
Excess Earnings	12	13	41 years
Other Regulatory Liabilities Being Paid	1	4	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	436	377	(b)
Deferred Investment Tax Credits	136	144	50 years
Over-recovery of Transition Charges	57	41	15 years
Unrealized Gain on Forward Commitments	46	41	5 years
Spent Nuclear Fuel Liability	43	43	(b)
Peak Demand Reduction/Energy Efficiency	31	40	2 years
Deferred State Income Tax Coal Credits	29	29	10 years
Other Regulatory Liabilities Being Paid	27	22	various
Total Regulatory Liabilities Being Paid	3,435	3,129	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,544	$ 3,195	

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

5. 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 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 $3.6 billion of construction expenditures, excluding equity AFUDC and capitalized interest, for 2013. 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 as of December 31, 2012:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,642	$ 3,928	$ 2,854	$ 2,908	$ 12,332
Energy and Capacity Purchase Contracts (b)	177	359	368	2,494	3,398
Construction Contracts for Capital Assets (c)	187	-	-	-	187
Total	$ 3,006	$ 4,287	$ 3,222	$ 5,402	$ 15,917

(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.
(c) 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.

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 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 credit facilities totaling $3.25 billion, under which we may issue up to $1.35 billion as letters of credit. As of December 31, 2012, the maximum future payments for letters of credit issued under the credit facilities were $131 million with maturities ranging from January 2013 to April 2014. In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

We have $402 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $407 million. The letters of credit have maturities ranging from March 2013 to July 2014. In February 2013, we extended certain bilateral letters of credit due in March 2013 to July 2014 and March 2015.

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 $115 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. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, 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, 2012, SWEPCo has collected approximately $59 million through a rider for final mine closure and reclamation costs, of which $18 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $41 million is recorded in Asset Retirement Obligations on the 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 6. As of December 31, 2012, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 12 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance 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. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. We will continue to defend against the claims. 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. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs' petition for rehearing by the full court was denied in November 2012, but the plaintiffs could seek further review in the U.S. Supreme Court. We believe the action is without merit and will continue 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. As of December 31, 2012, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five 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 three 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. I&M's reserve is approximately $10 million. As the remediation work is completed, I&M's cost may change 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.

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 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 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 amounts recovered in rates were $14 million, $14 million and $14 million for the years ended December 31, 2012, 2011 and 2010, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2012 and 2011, the total decommissioning trust fund balance was $1.4 billion and $1.3 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 and cash flows would be reduced and financial condition could be impacted 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. As of December 31, 2012 and 2011, 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 $308 million and $308 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.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $20 million and $14 million in 2012 and 2011, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2013. The proceeds reduced costs for dry cask storage. As of December 31, 2012, I&M has deferred $32 million in Prepayments and Other Current Assets and $13 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 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 $40 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, it could reduce future net income and cash flows and impact financial condition.

Cook Plant, Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant, Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in 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 cost approximately $400 million. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. In February 2013, we signed an agreement and received payment from NEIL to settle the remaining insurance claims. The settlement did not have a material impact on net income, cash flows or 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 reduce future net income and cash flows and impact financial condition.

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. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the dismissal of several cases involving AEP companies in Nevada to the Ninth Circuit Court of Appeals. Oral argument was held in October 2012. We will continue to defend the cases on appeal. We believe the provision we have is adequate. We believe the remaining exposure is immaterial.

6. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

ACQUISITIONS

2012

BlueStar Energy (Generation and Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million. This transaction also included goodwill of $15 million, intangible assets associated with sales contracts and customer accounts of $58 million and liabilities associated with supply contracts of $25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

2010

Valley Electric Membership Corporation (Utility Operations segment)

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO’s 30,000 customers in Louisiana.

Other Matters

Enron Bankruptcy

In February 2011, we reached a $425 million settlement covering all claims with BOA and Enron related to our purchase of Houston Pipeline Company (HPL) from Enron in 2001. As part of the settlement, we received title to the 55 billion cubic feet of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

DISPOSITIONS

2010

Texas Transmission Facilities (Utility Operations segment)

In 2010, TCC and TNC sold $66 million and $73 million, respectively, of transmission facilities to ETT. There were no gains or losses recorded on these sale transactions.

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

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain. We recorded the gain in Interest and Investment Income on the statement of income for the year ended December 31, 2010.

IMPAIRMENTS

2012

Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 (Utility Operations segment)

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, we performed an evaluation of the recoverability of generation assets. As a result, in November 2012, we, using generating unit specific estimated future cash flows, concluded that OPCo had a material impairment of certain generation assets. Under a market-based value approach, using level 3 unobservable inputs, we determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant (Utility Operations segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

2011

Turk Plant (Utility Operations segment)

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant Unit 5 FGD Project (MR5) (Utility Operations segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, we determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant Unit 5 (Utility Operations segment)

In the third quarter of 2011, we decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income.

7. 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 health 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	**2012**	**2011**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %
Rate of Compensation Increase	4.95 % (a)	4.85 % (a)	NA	NA

(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.

NA Not applicable.

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2012, 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		
	2012	2011	2010	2012	2011	2010
Discount Rate	4.55 %	5.05 %	5.60 %	4.75 %	5.25 %	5.85 %
Expected Return on Plan Assets	7.25 %	7.75 %	8.00 %	7.25 %	7.50 %	8.00 %
Rate of Compensation Increase	4.85 %	4.85 %	4.60 %	NA	NA	NA

NA Not applicable.

The expected return on plan assets 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	2012	2011
Initial	7.00 %	7.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2016

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	$ 24	$ (19)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	118	(89)

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. As of December 31, 2012, 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, 2012 and 2011

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	
	2012	**2011**	**2012**	**2011**
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1	$ 4,991	$ 4,807	$ 2,227	$ 2,125
Service Cost	76	72	47	42
Interest Cost	223	237	103	109
Actuarial Loss	299	169	148	253
Plan Amendment Prior Service Credit	-	-	(570)	(196)
Curtailment and Settlements	(1)	-	-	1
Benefit Payments	(383)	(294)	(151)	(150)
Participant Contributions	-	-	35	34
Medicare Subsidy	-	-	10	9
Benefit Obligation as of December 31	$ 5,205	$ 4,991	$ 1,849	$ 2,227
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 4,303	$ 3,858	$ 1,410	$ 1,461
Actual Gain (Loss) on Plan Assets	560	282	178	(14)
Company Contributions	216	457	96	79
Participant Contributions	-	-	35	34
Benefit Payments	(383)	(294)	(151)	(150)
Fair Value of Plan Assets as of December 31	$ 4,696	$ 4,303	$ 1,568	$ 1,410
Underfunded Status as of December 31	$ (509)	$ (688)	$ (281)	$ (817)

Benefit Amounts Recognized on the Balance Sheets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	**2011**	**2012**	**2011**
	(in millions)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (7)	$ (8)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(502)	(680)	(277)	(813)
Underfunded Status	$ (509)	$ (688)	$ (281)	$ (817)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in millions)			
Net Actuarial Loss	$ 2,111	$ 2,208	$ 989	$ 979
Prior Service Cost (Credit)	11	10	(762)	(210)
Transition Obligation	-	-	-	1
Recorded as				
Regulatory Assets	$ 1,774	$ 1,818	$ 108	$ 479
Deferred Income Taxes	122	140	42	102
Net of Tax AOCI	226	260	77	189

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2012 and 2011 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
Components	(in millions)			
Actuarial Loss During the Year	$ 58	$ 201	$ 67	$ 370
Prior Service Credit	-	-	(570)	(191)
Amortization of Actuarial Loss	(155)	(122)	(57)	(29)
Amortization of Prior Service Credit (Cost)	1	(1)	18	1
Amortization of Transition Obligation	-	-	(1)	(2)
Change for the Year	$ (96)	$ 78	$ (543)	$ 149

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,308	$ -	$ -	$ -	$ 1,308	27.9 %
International	497	-	-	-	497	10.5 %
Real Estate Investment Trusts	91	-	-	-	91	1.9 %
Common Collective Trust - International	-	4	-	-	4	0.1 %
Subtotal - Equities	1,896	4	-	-	1,900	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	32	-	-	32	0.7 %
United States Government and Agency Securities	-	715	-	-	715	15.2 %
Corporate Debt	-	1,235	-	-	1,235	26.3 %
Foreign Debt	-	199	-	-	199	4.2 %
State and Local Government	-	44	-	-	44	0.9 %
Other - Asset Backed	-	36	-	-	36	0.8 %
Subtotal - Fixed Income	-	2,261	-	-	2,261	48.1 %
Real Estate	-	-	220	-	220	4.7 %
Alternative Investments	-	-	195	-	195	4.2 %
Securities Lending	-	80	-	-	80	1.7 %
Securities Lending Collateral (a)	-	-	-	(91)	(91)	(1.9)%
Cash and Cash Equivalents	-	126	-	-	126	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	5	5	0.1 %
Total	$ 1,896	$ 2,471	$ 415	$ (86)	$ 4,696	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 accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2012	$ 6	$ 163	$ 161	$ 330
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	30	10	40
Relating to Assets Sold During the Period	(2)	-	4	2
Purchases and Sales	(4)	27	20	43
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 220	$ 195	$ 415

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 422	$ -	$ -	$ -	$ 422	26.9 %
International	505	-	-	-	505	32.2 %
Subtotal - Equities	927	-	-	-	927	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	72	-	-	72	4.6 %
United States Government and Agency Securities	-	82	-	-	82	5.2 %
Corporate Debt	-	155	-	-	155	9.9 %
Foreign Debt	-	26	-	-	26	1.7 %
State and Local Government	-	7	-	-	7	0.5 %
Other - Asset Backed	-	10	-	-	10	0.6 %
Subtotal - Fixed Income	-	352	-	-	352	22.5 %
Trust Owned Life Insurance:						
International Equities	-	52	-	-	52	3.3 %
United States Bonds	-	163	-	-	163	10.3 %
Cash and Cash Equivalents	62	11	-	-	73	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	1	1	0.1 %
Total	$ 989	$ 578	$ -	$ 1	$ 1,568	100.0 %

(a) 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 as of December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,455	$ -	$ -	$ -	$ 1,455	33.8 %
International	399	-	-	-	399	9.3 %
Real Estate Investment Trusts	104	-	-	-	104	2.4 %
Common Collective Trust - International	-	128	-	-	128	3.0 %
Subtotal - Equities	1,958	128	-	-	2,086	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.6 %
United States Government and Agency Securities	-	566	-	-	566	13.2 %
Corporate Debt	-	985	6	-	991	23.0 %
Foreign Debt	-	190	-	-	190	4.4 %
State and Local Government	-	48	-	-	48	1.1 %
Other - Asset Backed	-	26	-	-	26	0.6 %
Subtotal - Fixed Income	-	1,841	6	-	1,847	42.9 %
Real Estate	-	-	163	-	163	3.8 %
Alternative Investments	-	-	161	-	161	3.7 %
Securities Lending	-	215	-	-	215	5.0 %
Securities Lending Collateral (a)	-	-	-	(236)	(236)	(5.5)%
Cash and Cash Equivalents	-	93	-	-	93	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(26)	(26)	(0.6)%
Total	$ 1,958	$ 2,277	$ 330	$ (262)	$ 4,303	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 accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2011	$ -	$ 83	$ 130	$ 213
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	22	9	31
Relating to Assets Sold During the Period	-	-	3	3
Purchases and Sales	-	58	19	77
Transfers into Level 3	6	-	-	6
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 6	$ 163	$ 161	$ 330

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 348	$ -	$ -	$ -	$ 348	24.7 %
International	380	-	-	-	380	27.0 %
Common Collective Trust - Global	-	99	-	-	99	7.0 %
Subtotal - Equities	728	99	-	-	827	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	69	-	-	69	4.9 %
United States Government and Agency Securities	-	81	-	-	81	5.7 %
Corporate Debt	-	152	-	-	152	10.8 %
Foreign Debt	-	32	-	-	32	2.3 %
State and Local Government	-	9	-	-	9	0.6 %
Other - Asset Backed	-	2	-	-	2	0.1 %
Subtotal - Fixed Income	-	345	-	-	345	24.4 %
Trust Owned Life Insurance:						
International Equities	-	46	-	-	46	3.3 %
United States Bonds	-	158	-	-	158	11.2 %
Cash and Cash Equivalents	17	23	-	-	40	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(6)	(6)	(0.5)%
Total	$ 745	$ 671	$ -	$ (6)	$ 1,410	100.0 %

(a) 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.

Accumulated Benefit Obligation	December 31, 2012	December 31, 2011
	(in millions)	
Qualified Pension Plan	$ 5,001	$ 4,808
Nonqualified Pension Plans	82	89
Total	$ 5,083	$ 4,897

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 as of December 31, 2012 and 2011 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2012	2011
	(in millions)	
Projected Benefit Obligation	$ 5,205	$ 4,991
Accumulated Benefit Obligation	$ 5,083	$ 4,897
Fair Value of Plan Assets	4,696	4,303
Underfunded Accumulated Benefit Obligation	$ (387)	$ (594)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $108 million and the OPEB plans of $4 million during 2013. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, we may also make additional discretionary contributions to maintain the funded status of the plan. For the OPEB plans, expected payments include the payment of unfunded benefits.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage will be capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. In December 2011, we amended the prescription drug program for certain participants. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. 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)	
2013	$ 340	$ 140	$ -
2014	349	146	-
2015	356	153	-
2016	359	162	-
2017	364	171	-
Years 2018 to 2022, in Total	1,844	990	2

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, 2012, 2011 and 2010:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in millions)					
Service Cost	$ 76	$ 72	$ 111	$ 47	$ 42	$ 47
Interest Cost	223	237	253	103	109	113
Expected Return on Plan Assets	(319)	(314)	(312)	(101)	(109)	(105)
Curtailment	-	-	-	-	1	-
Amortization of Transition Obligation	-	-	-	1	2	27
Amortization of Prior Service Cost (Credit)	(1)	1	-	(18)	(1)	-
Amortization of Net Actuarial Loss	155	122	89	57	29	29
Net Periodic Benefit Cost	134	118	141	89	73	111
Capitalized Portion	(42)	(37)	(44)	(28)	(22)	(35)
Net Periodic Benefit Cost Recognized as Expense	$ 92	$ 81	$ 97	$ 61	$ 51	$ 76

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2013 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 176	$ 64
Prior Service Cost (Credit)	3	(69)
Total Estimated 2013 Amortization	$ 179	$ (5)
Expected to be Recorded as		
Regulatory Asset	$ 148	$ (7)
Deferred Income Taxes	11	1
Net of Tax AOCI	20	1
Total	$ 179	$ (5)

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. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $66 million in 2012, $64 million in 2011 and $61 million in 2010.

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.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by any employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2012 and 2011, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA. Contributions in 2012, 2011 and 2010 were made under a collective bargaining agreement that is scheduled to expire December 31, 2013. We contributed immaterial amounts in 2012, 2011 and 2010 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2012, 2011 and 2010. The contributions we made did not include a surcharge. There are no minimum contributions for future years.

8. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. 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. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

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

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a reportable 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 were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

The tables below present our reportable segment information for the years ended December 31, 2012, 2011 and 2010 and balance sheet information as of December 31, 2012 and 2011. These amounts include certain estimates and allocations where necessary.

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Year Ended December 31, 2012							
Revenues from:							
External Customers	$ 13,670	$ 7	$ 647	$ 599	$ 22	$ -	$ 14,945
Other Operating Segments	108	17	20	1	8	(154)	-
Total Revenues	$ 13,778	$ 24	$ 667	$ 600	$ 30	$ (154)	$ 14,945
Asset Impairments and Other Related Charges	$ 300	$ -	$ -	$ -	$ -	$ -	$ 300
Depreciation and Amortization	1,734	3	29	28	-	(12)(b)	1,782
Interest Income	7	-	-	-	20	(19)	8
Carrying Costs Income	53	-	-	-	-	-	53
Interest Expense	882	3	17	19	102	(35)(b)	988
Income Tax Expense	560	17	7	3	17	-	604
Net Income (Loss)	1,299	43	15	7	(102)	-	1,262
Gross Property Additions	2,625	392	31	71	-	-	3,119

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Year Ended December 31, 2011							
Revenues from:							
External Customers	$ 14,088	$ 3	$ 696	$ 305	$ 24	$ -	$ 15,116
Other Operating Segments	112	5	20	1	8	(146)	-
Total Revenues	$ 14,200	$ 8	$ 716	$ 306	$ 32	$ (146)	$ 15,116
Asset Impairments and Other Related Charges	$ 139	$ -	$ -	$ -	$ -	$ -	$ 139
Depreciation and Amortization	1,613	-	28	25	2	(13)(b)	1,655
Interest Income	29	-	-	(1)	17	(18)	27
Carrying Costs Income	393	-	-	-	-	-	393
Interest Expense	886	1	18	18	43	(33)(b)	933
Income Tax Expense (Credit)	722	2	24	(18)	88	-	818
Income (Loss) Before Extraordinary Item	$ 1,549	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,576
Extraordinary Item, Net of Tax	373	-	-	-	-	-	373
Net Income (Loss)	$ 1,922	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,949
Gross Property Additions	$ 2,405	$ 263	$ 18	$ 2	$ 214	$ -	$ 2,902

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility 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	105	1	22	-	14	(142)	-
Total Revenues	$ 13,792	$ 1	$ 588	$ 173	$ 15	$ (142)	$ 14,427
Asset Impairments and Other Related Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation and Amortization	1,598	-	24	30	2	(13)(b)	1,641
Interest Income	8	-	-	2	31	(20)	21
Carrying Costs Income	70	-	-	-	-	-	70
Interest Expense	942	-	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	651	(1)	19	(20)	(6)	-	643
Net Income (Loss)	1,192	9	37	25	(45)	-	1,218
Gross Property Additions	2,440	35	23	1	1	-	2,500

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2012							
Total Property, Plant and Equipment	$ 55,707	$ 748	$ 636	$ 621	$ 8	$ (266)	$ 57,454
Accumulated Depreciation and Amortization	18,344	4	161	246	7	(71)	18,691
Total Property, Plant and Equipment - Net	$ 37,363	$ 744	$ 475	$ 375	$ 1	$ (195)	$ 38,763
Total Assets	$ 51,477	$ 1,216	$ 670	$ 1,005	$ 17,191	$ (17,192) (c)	$ 54,367
Investments in Equity Method Investees	24	393	43	-	5	-	465

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2011							
Total Property, Plant and Equipment	$ 54,396	$ 323	$ 608	$ 590	$ 11	$ (258)	$ 55,670
Accumulated Depreciation and Amortization	18,393	-	136	219	10	(59)	18,699
Total Property, Plant and Equipment - Net	$ 36,003	$ 323	$ 472	$ 371	$ 1	$ (199)	$ 36,971
Total Assets	$ 50,093	$ 594	$ 659	$ 868	$ 16,751	$ (16,742) (c)	$ 52,223
Investments in Equity Method Investees	24	256	17	-	2	-	299

(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 were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

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

9. 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

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact. To accomplish our objectives, we primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. 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, 2012 and 2011:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2012	Volume December 31, 2011	Unit of Measure
	(in millions)		
Commodity:			
Power	498	609	MWhs
Coal	10	21	Tons
Natural Gas	147	100	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 235	$ 226	USD
Interest Rate and Foreign Currency	$ 1,199	$ 907	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 activities 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 future borrowings of fixed-rate debt. Our forecasted 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 on the balance sheets 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, 2012 and 2011 balance sheets, we netted $7 million and $26 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $50 million and $133 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 the balance sheets as of December 31, 2012 and 2011:

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 589	$ 32	$ 3	$ 624	$ (433)	$ 191
Long-term Risk Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ (12)	$ (37)	$ 139	$ 51	$ 190

Fair Value of Derivative Instruments
December 31, 2011

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 852	$ 24	$ -	$ 876	$ (683)	$ 193
Long-term Risk Management Assets	641	15	-	656	(253)	403
Total Assets	1,493	39	-	1,532	(936)	596
Current Risk Management Liabilities	847	29	20	896	(746)	150
Long-term Risk Management Liabilities	483	15	22	520	(325)	195
Total Liabilities	1,330	44	42	1,416	(1,071)	345
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163	$ (5)	$ (42)	$ 116	$ 135	$ 251

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts primarily include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2012, 2011 and 2010:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2012	2011	2010
		(in millions)	
Utility Operations Revenues	$ 21	$ 46	$ 85
Other Revenues	39	20	9
Regulatory Assets (a)	(43)	(22)	(9)
Regulatory Liabilities (a)	8	(3)	38
Total Gain (Loss) on Risk Management Contracts	$ 25	$ 41	$ 123

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

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 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 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 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 the statements of income. During 2012, the fair value changes for both our hedging instruments and hedged long-term debt were immaterial. During 2011 and 2010, we recognized gains of $3 million and $6 million, respectively, on our hedging instruments and offsetting losses of $6 million and $6 million, respectively, on our long-term debt. For 2012, 2011 and 2010, hedge ineffectiveness was immaterial.

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 the 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 and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the statements of income, or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2012, 2011 and 2010, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2012, 2011 and 2010, 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) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2012, 2011 and 2010, 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 the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2012, 2011 and 2010, we designated foreign currency derivatives as cash flow hedges.

During 2012, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012, 2011 and 2010. 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, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(15)	(14)	(29)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	13	-	13
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ (38)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	(5)	(28)	(33)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	3	-	3
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	(2)	-	(2)
Other Operation Expense	(1)	-	(1)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	4	4
Property, Plant and Equipment	(1)	-	(1)
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

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 Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

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

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2012 and 2011 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 24	$ -	$ 24
Hedging Liabilities (a)	36	37	73
AOCI Gain (Loss) Net of Tax	(8)	(30)	(38)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(8)	(4)	(12)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 20	$ -	$ 20
Hedging Liabilities (a)	25	42	67
AOCI Gain (Loss) Net of Tax	(3)	(20)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3)	(2)	(5)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the 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, 2012, 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 33 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. AEP and its subsidiaries have not experienced a downgrade below investment grade. The following table represents: (a) our 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, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 7	$ 32
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	32	39
Amount Attributable to RTO and ISO Activities	31	38

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 by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. 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, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 469	$ 515
Amount of Cash Collateral Posted	8	56
Additional Settlement Liability if Cross Default Provision is Triggered	328	291

10. 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 classified as Level 2 measurement inputs. 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, 2012 and 2011 are summarized in the following table:

	December 31, 2012		December 31, 2011	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,757	$ 20,907	$ 16,516	$ 19,259

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds, marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS. See “Other Temporary Investments” section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2012			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 241	$ -	$ -	$ 241
Fixed Income Securities:				
Mutual Funds	65	2	-	67
Equity Securities - Mutual Funds	10	6	-	16
Total Other Temporary Investments	$ 316	$ 8	$ -	$ 324

	December 31, 2011			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 216	$ -	$ -	$ 216
Fixed Income Securities:				
Mutual Funds	64	-	-	64
Equity Securities - Mutual Funds	11	3	-	14
Total Other Temporary Investments	$ 291	$ 3	$ -	$ 294

(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, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	**2011**	**2010**
		(in millions)	
Proceeds from Investment Sales	$ -	$ 268	$ 455
Purchases of Investments	2	154	503
Gross Realized Gains on Investment Sales	-	4	16
Gross Realized Losses on Investment Sales	-	-	-

As of December 31, 2012 and 2011, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2012, fixed income securities are primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

The following table provides details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes for the years ended December 31, 2012 and 2011. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Years Ended December 31, 2012 and 2011

	(in millions)
Balance in AOCI as of December 31, 2010	$ 4
Changes in Fair Value Recognized in AOCI	1
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:	
Interest Income	(3)
Balance in AOCI as of December 31, 2011	2
Changes in Fair Value Recognized in AOCI	2
Balance in AOCI as of December 31, 2012	$ 4

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 as of December 31, 2012 and December 31, 2011:

	December 31,					
	2012			2011		
	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	$ 17	$ -	$ -	$ 18	$ -	$ -
Fixed Income Securities:						
United States Government	648	58	(1)	544	61	(1)
Corporate Debt	35	5	(1)	54	5	(2)
State and Local Government	270	1	(1)	330	-	(2)
Subtotal Fixed Income Securities	953	64	(3)	928	66	(5)
Equity Securities - Domestic	736	285	(77)	646	215	(80)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,706	$ 349	$ (80)	$ 1,592	$ 281	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
	(in millions)		
Proceeds from Investment Sales	$ 988	$ 1,111	$ 1,362
Purchases of Investments	1,045	1,167	1,415
Gross Realized Gains on Investment Sales	25	33	12
Gross Realized Losses on Investment Sales	9	22	2

The adjusted cost of debt securities was $889 million and $862 million as of December 31, 2012 and 2011, respectively. The adjusted cost of equity securities was $451 million and $431 million as of December 31, 2012 and 2011, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2012 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 81
1 year – 5 years	373
5 years – 10 years	266
After 10 years	233
Total	$ 953

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, 2012 and 2011. 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 our valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ 1	$ -	$ 272	$ 279
Other Temporary Investments					
Restricted Cash (a)	227	5	-	9	241
Fixed Income Securities:					
Mutual Funds	67	-	-	-	67
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	310	5	-	9	324
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	47	938	131	(599)	517
Cash Flow Hedges:					
Commodity Hedges (c)	8	28	-	(12)	24
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	14	14
Total Risk Management Assets	55	968	131	(595)	559
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	7	-	-	10	17
Fixed Income Securities:					
United States Government	-	648	-	-	648
Corporate Debt	-	35	-	-	35
State and Local Government	-	270	-	-	270
Subtotal Fixed Income Securities	-	953	-	-	953
Equity Securities - Domestic (b)	736	-	-	-	736
Total Spent Nuclear Fuel and Decommissioning Trusts	743	953	-	10	1,706
Total Assets	$ 1,114	$ 1,927	$ 131	$ (304)	$ 2,868
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 45	$ 838	$ 45	$ (636)	$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	-	48	-	(12)	36
Interest Rate/Foreign Currency Hedges	-	37	-	-	37
Fair Value Hedges	-	2	-	2	4
Total Risk Management Liabilities	$ 45	$ 925	$ 45	$ (646)	$ 369

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ -	$ -	$ 215	$ 221
Other Temporary Investments					
Restricted Cash (a)	191	-	-	25	216
Fixed Income Securities:					
Mutual Funds	64	-	-	-	64
Equity Securities - Mutual Funds (b)	14	-	-	-	14
Total Other Temporary Investments	269	-	-	25	294
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	47	1,299	147	(945)	548
Cash Flow Hedges:					
Commodity Hedges (c)	15	23	-	(18)	20
De-designated Risk Management Contracts (e)	-	-	-	28	28
Total Risk Management Assets	62	1,322	147	(935)	596
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	-	5	-	13	18
Fixed Income Securities:					
United States Government	-	544	-	-	544
Corporate Debt	-	54	-	-	54
State and Local Government	-	330	-	-	330
Subtotal Fixed Income Securities	-	928	-	-	928
Equity Securities - Domestic (b)	646	-	-	-	646
Total Spent Nuclear Fuel and Decommissioning Trusts	646	933	-	13	1,592
Total Assets	$ 983	$ 2,255	$ 147	$ (682)	$ 2,703
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 43	$ 1,209	$ 78	$ (1,052)	$ 278
Cash Flow Hedges:					
Commodity Hedges (c)	-	43	-	(18)	25
Interest Rate/Foreign Currency Hedges	-	42	-	-	42
Total Risk Management Liabilities	$ 43	$ 1,294	$ 78	$ (1,070)	$ 345

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 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) The December 31, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $9 million in 2013, $(3) million in periods 2014-2016 and ($4) million in periods 2017-2018; Level 2 matures $16 million in 2013, $61 million in periods 2014-2016, $16 million in periods 2017-2018 and $7 million in periods 2019-2030; Level 3 matures $18 million in 2013, $31 million in periods 2014-2016, $13 million in periods 2017-2018 and $24 million in periods 2019-2030. Risk management commodity contracts are substantially comprised of power contracts.

(e) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(g) The December 31, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $3 million in 2012, $7 million in periods 2013-2015 and ($6) million in periods 2016-2018; Level 2 matures $21 million in 2012, $50 million in periods 2013-2015, $11 million in periods 2016-2017 and $8 million in periods 2018-2030; Level 3 matures ($19) million in 2012, $44 million in periods 2013-2015, $18 million in periods 2016-2017 and $26 million in periods 2018-2030. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012, 2011 and 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, 2012	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2011	$ 69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(15)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	29
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	32
Transfers into Level 3 (d) (e)	1
Transfers out of Level 3 (e) (f)	(35)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	5
Balance as of December 31, 2012	$ 86

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2010	$ 85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(10)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(3)
Transfers into Level 3 (d) (e)	13
Transfers out of Level 3 (e) (f)	(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(13)
Balance as of December 31, 2011	$ 69

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) (e)	18
Transfers out of Level 3 (e) (f)	(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2010	$ 85

(a) Included in revenues on the 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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following table quantifies the significant unobservable inputs used in developing the fair value of our Level 3 positions as of December 31, 2012:

	Fair Value		Valuation	Significant	Input/Range	
	Assets	Liabilities	Technique	Unobservable Input	Low	High
	(in millions)					
Energy Contracts	$ 124	$ 38	Discounted Cash Flow	Forward Market Price (a)	$ 9.40	$ 111.97
				Counterparty Credit Risk (b)	397	
FTRs	7	7	Discounted Cash Flow	Forward Market Price (a)	(3.21)	14.79
Total	$ 131	$ 45				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

11. INCOME TAXES

The details of our consolidated income taxes before extraordinary item as reported are as follows:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Federal:			
Current	$ (52)	$ 20	$ (134)
Deferred	698	786	760
Total Federal	646	806	626
State and Local:			
Current	35	37	(20)
Deferred	(77)	(25)	38
Total State and Local	(42)	12	18
International:			
Current	-	-	(1)
Deferred	-	-	-
Total International	-	-	(1)
Income Tax Expense	$ 604	$ 818	$ 643

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, 2012	2011	2010
		(in millions)	
Net Income	$ 1,262	$ 1,949	$ 1,218
Extraordinary Item, Net of Tax of $(112) million in 2011	-	(373)	-
Income Before Extraordinary Item	1,262	1,576	1,218
Income Tax Expense	604	818	643
Pretax Income	$ 1,866	$ 2,394	$ 1,861
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 653	$ 838	$ 651
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	39	41	47
Investment Tax Credits, Net	(14)	(15)	(16)
Energy Production Credits	-	(18)	(20)
State and Local Income Taxes, Net	(33)	(22)	11
Removal Costs	(18)	(20)	(19)
AFUDC	(39)	(42)	(33)
Medicare Subsidy	3	1	12
Valuation Allowance	6	86	-
Tax Reserve Adjustments	17	2	(16)
Other	(10)	(33)	26
Income Tax Expense	$ 604	$ 818	$ 643
Effective Income Tax Rate	32.4 %	34.2 %	34.6 %

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

	December 31, 2012	2011
	(in millions)	
Deferred Tax Assets	$ 2,900	$ 2,855
Deferred Tax Liabilities	(12,098)	(11,185)
Net Deferred Tax Liabilities	$ (9,198)	$ (8,330)
Property Related Temporary Differences	$ (6,752)	$ (5,963)
Amounts Due from Customers for Future Federal Income Taxes	(289)	(259)
Deferred State Income Taxes	(683)	(668)
Securitized Transition Assets	(780)	(621)
Regulatory Assets	(781)	(1,208)
Postretirement Benefits	266	424
Accrued Pensions	104	149
Deferred Income Taxes on Other Comprehensive Loss	184	254
Accrued Nuclear Decommissioning	(475)	(436)
Net Operating Loss Carryforward	194	125
Tax Credit Carryforward	104	182
Valuation Allowance	(92)	(86)
All Other, Net	(198)	(223)
Net Deferred Tax Liabilities	$ (9,198)	$ (8,330)

AEP System Tax Allocation Agreement

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.

Federal and State Income Tax Audit Status

We are no longer subject to U.S. federal examination for years before 2009. We completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not materially impact net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. 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 materially impact 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. We believe 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 2008. In March 2012, we settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not materially impact net income, cash flows or financial condition.

Net Income Tax Operating Loss Carryforward

In 2012 and 2011, we recognized federal net income tax operating losses of $366 million and $226 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book-versus-tax temporary differences. We also had state net income tax operating loss carryforwards as indicated in the table below.

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Louisiana	$ 314	2027
Oklahoma	137	2031
Tennessee	13	2026
Virginia	329	2031
West Virginia	897	2032

As a result, we accrued deferred federal, state and local income tax benefits in 2012 and 2011. We expect to realize the federal, state and local cash flow benefits in future periods as there was insufficient capacity in prior periods to carry the net operating losses back. We anticipate future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2032.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009, along with lower federal and state taxable income in 2010, resulted in unused federal and state income tax credits. As of December 31, 2012, we have total federal tax credit carryforwards of $104 million and total state tax credit carryforwards of $82 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $70 million will expire in the years 2028 through 2031 and the state coal tax credits of $29 million will expire in the years 2013 through 2021.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. We do not anticipate state taxable income will be sufficient in future periods to realize the tax benefits of all state income tax credits before they expire and we have provided a valuation allowance accordingly.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated was the net income tax operating losses sustained in 2012, 2011 and 2009. On the basis of this evaluation of available positive and negative evidence, as of December 31, 2012, a valuation allowance of $36 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to measure only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted or if objective negative evidence in the form of cumulative losses is no longer present and additional weight may be given to subjective evidence, such as our projections for growth.

For a discussion of the tax implications of the unrealized capital loss resulting from our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 6.

Uncertain Tax Positions

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation expense 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,		
	2012	**2011**	**2010**
		(in millions)	
Interest Expense	$ 11	$ 8	$ 8
Interest Income	-	22	11
Reversal of Prior Period Interest Expense	1	13	5

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

	December 31,	
	2012	**2011**
	(in millions)	
Accrual for Receipt of Interest	$ -	$ 13
Accrual for Payment of Interest and Penalties	7	6

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

	2012	**2011**	**2010**
		(in millions)	
Balance as of January 1,	$ 168	$ 219	$ 237
Increase - Tax Positions Taken During a Prior Period	23	51	40
Decrease - Tax Positions Taken During a Prior Period	(16)	(43)	(43)
Increase - Tax Positions Taken During the Current Year	121	10	-
Decrease - Tax Positions Taken During the Current Year	-	-	(6)
Decrease - Settlements with Taxing Authorities	(25)	(31)	(2)
Decrease - Lapse of the Applicable Statute of Limitations	(4)	(38)	(7)
Balance as of December 31,	$ 267	$ 168	$ 219

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $149 million, $111 million and $112 million for 2012, 2011 and 2010, 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

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 materially impact 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. Due to 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 impact 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 2010 Act) was enacted in September 2010. Included in the 2010 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 2010 Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2011 and 2010. The enacted provisions will not materially impact net income or financial condition but had a favorable impact on cash flows of $318 million in 2010.

In December 2011, the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. In November 2012, the effective date was moved to tax years beginning in 2014. Further, the notice stated that the U.S. Treasury Department anticipates that the final regulations will contain changes from the temporary regulations. We will evaluate the impact of these regulations once they are issued.

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of the 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions will not materially impact net income or financial condition but are expected to have a favorable impact on cash flows in 2013.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rates from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012.

During the third quarter of 2012, the state of West Virginia achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not materially impact net income, cash flows or financial condition.

12. 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. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Years Ended December 31,		
Lease Rental Costs	**2012**	**2011**	**2010**
		(in millions)	
Net Lease Expense on Operating Leases	$ 346	$ 343	$ 343
Amortization of Capital Leases	73	72	97
Interest on Capital Leases	29	32	26
Total Lease Rental Costs	$ 448	$ 447	$ 466

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

	December 31,	
Property, Plant and Equipment Under Capital Leases	**2012**	**2011**
	(in millions)	
Generation	$ 117	$ 104
Other Property, Plant and Equipment	495	485
Total Property, Plant and Equipment Under Capital Leases	612	589
Accumulated Amortization	173	137
Net Property, Plant and Equipment Under Capital Leases	$ 439	$ 452
Obligations Under Capital Leases		
Noncurrent Liability	$ 375	$ 384
Liability Due Within One Year	74	74
Total Obligations Under Capital Leases	$ 449	$ 458

Future minimum lease payments consisted of the following as of December 31, 2012:

Future Minimum Lease Payments	**Capital Leases**	**Noncancelable Operating Leases**
	(in millions)	
2013	$ 95	$ 302
2014	79	275
2015	65	257
2016	59	233
2017	63	219
Later Years	244	1,034
Total Future Minimum Lease Payments	605	$ 2,320
Less Estimated Interest Element	156	
Estimated Present Value of Future Minimum Lease Payments	$ 449	

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the 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. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of December 31, 2012, the maximum potential loss for these lease agreements was approximately $19 million assuming the fair value of the equipment is zero at the end of the lease term. Obligations under these master lease agreements are included in the future minimum lease payments schedule earlier in this note.

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. AEP, AEGCo and I&M have no 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, 2012 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2013	$ 74	$ 74
2014	74	74
2015	74	74
2016	74	74
2017	74	74
Later Years	369	369
Total Future Minimum Lease Payments	$ 739	$ 739

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 $14 million for I&M and $15 million for SWEPCo for the remaining railcars as of December 31, 2012. 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 and SWEPCo's is approximately $13 million 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. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2012 and 2011 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, 2012 and 2011 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 had a variable rate based on one month LIBOR and was accounted for as a capital lease with lease terms up to 60 months. This lease was terminated with the March 2012 refueling.

13. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2012, 2011 and 2010:

Shares of AEP Common Stock	Issued	Held in Treasury
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
Issued	2,644,579	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2011	503,759,460	20,336,592
Issued	2,245,502	-
Balance, December 31, 2012	506,004,962	20,336,592

Preferred Stock

In December 2011, AEP subsidiaries redeemed all of their outstanding preferred stock with a par value of $60 million at a premium, resulting in a $2.8 million loss, which is included in Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense on the statement of income.

Long-term Debt

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2012	Interest Rate Ranges as of December 31, 2012	2011		Outstanding as of December 31, 2012		2011
					(in millions)		
Senior Unsecured Notes (a)							
2012-2042	5.46%	0.685%-8.13%	0.955%-8.13%	$	12,712	$	11,737
Pollution Control Bonds (b)							
2012-2038 (c)	3.58%	0.11%-6.30%	0.06%-6.30%		1,958		2,112
Notes Payable (d)							
2012-2032	4.35%	1.913%-8.03%	2.029%-8.03%		427		402
Securitization Bonds (e)							
2013-2024	4.21%	0.88%-6.25%	4.98%-6.25%		2,281		1,688
Junior Subordinated Debentures (a)							
2063			8.75%		-		315
Spent Nuclear Fuel Obligation (f)					265		265
Other Long-term Debt (g)							
2015-2059	2.63%	1.72%-13.718%	3.00%-13.718%		140		29
Fair Value of Interest Rate Hedges					3		7
Unamortized Discount, Net					(29)		(39)
Total Long-term Debt Outstanding					17,757		16,516
Long-term Debt Due Within One Year					2,171		1,433
Long-term Debt				$	15,586	$	15,083

(a) In 2012, AEP issued $850 million of Senior Unsecured Notes used to retire $243 million of Senior Unsecured Notes and $315 million of Junior Subordinated Debentures.
(b) 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.
(c) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on the balance sheets.
(d) Notes payable represent outstanding promissory notes issued under term loan agreements and 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.
(e) In 2012, AEP Texas Central Transition Funding III LLC issued $800 million of Securitization Bonds (see Note 15).
(f) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 5).
(g) In 2012, I&M issued a $110 million three-year credit facility to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2012 is payable as follows:

	2013	2014	2015	2016	2017	After 2017	Total
				(in millions)			
Principal Amount	$ 2,171	$ 1,169	$ 1,438	$ 840	$ 1,655	$ 10,513	$ 17,786
Unamortized Discount, Net							(29)
Total Long-term Debt Outstanding							$ 17,757

In January 2013 and February 2013, I&M retired $12 million and $11 million, respectively, of Notes Payable related to DCC Fuel.

In January 2013, TCC retired $105 million of its outstanding Securitization Bonds.

In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

As of December 31, 2012, trustees held, on our behalf, $583 million of our reacquired Pollution Control Bonds.

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.

Utility Subsidiaries' Restrictions

Various financing arrangements 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, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of December 31, 2012, 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 $6 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 book value of the common stock. 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, 2012, we had credit facilities totaling $3.25 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2012 was $1.2 billion and the weighted average interest rate of commercial paper outstanding during 2012 was 0.44%. Our outstanding short-term debt was as follows:

	December 31,			
	2012		2011	
Type of Debt	**Outstanding Amount (in millions)**	**Interest Rate (a)**	**Outstanding Amount (in millions)**	**Interest Rate (a)**
Securitized Debt for Receivables (b)	$ 657	0.26 %	$ 666	0.27 %
Commercial Paper	321	0.42 %	967	0.51 %
Line of Credit – Sabine (c)	3	1.82 %	17	1.79 %
Total Short-term Debt	$ 981		$ 1,650	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

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. 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 2012, we renewed AEP Credit's receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2012	**2011**	**2010**
		(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	0.26 %	0.27 %	0.31 %
Net Uncollectible Accounts Receivable Written Off	$ 29	$ 37	$ 22

	December 31,	
	2012	**2011**
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 835	$ 902
Total Principal Outstanding	657	666
Delinquent Securitized Accounts Receivable	37	38
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	21	18
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	316	370

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.

14. 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. As of December 31, 2012, 17,907,559 shares remained available for issuance under the LTIP plan. 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 2012, 2011 or 2010 but we do have outstanding stock options from grants in earlier periods that 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 1 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 intrinsic value of options exercised is as follows:

Stock Options	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Intrinsic Value of Options Exercised (a)	$ 1,699	$ 1,202	$ 2,058

(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, 2012, 2011 and 2010 is as follows:

	2012		2011		2010	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding as of January 1,	321	$ 29.35	551	$ 32.88	1,089	$ 32.78
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(128)	28.21	(104)	27.39	(448)	31.53
Forfeited/Expired	(5)	27.26	(126)	46.40	(90)	38.44
Outstanding as of December 31,	188	30.17	321	29.35	551	32.88
Options Exercisable as of December 31,	188	$ 30.17	321	$ 29.35	551	$ 32.88

NA Not applicable.

The following table summarizes information about AEP stock options outstanding and exercisable as of December 31, 2012:

2012 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)
$27.95 - $30.76	188	0.99	$ 30.17	$ 2,358

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

Performance Units

Our performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and 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. 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 has a value equivalent to shares of AEP common stock. AEP Career Shares 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 record 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 the 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, 2012, 2011 and 2010 as follows:

Performance Units	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	546	7	736
Weighted Average Unit Fair Value at Grant Date	$ 41.38	$ 38.39	$ 35.43
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	138	198	211
Weighted Average Grant Date Fair Value	$ 40.97	$ 37.31	$ 34.70
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 but are not paid in cash until after the participant's termination of employment.

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 number of performance units earned but may not increase the number earned. The performance scores for all open performance periods prior to those granted in 2012 are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the electric utility and multi utility sub-industry segments 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. For the performance units granted in 2012, the three-year total shareholder return peer group was changed to the S&P 500 Electric Utility Index.

The certified performance scores and units earned for the three-year period ended December 31, 2012, 2011 and 2010 were as follows:

Performance Units	Years Ended December 31, 2012	2011	2010
Certified Performance Score	99.7 %	89.8 %	55.8 %
Performance Units Earned	1,096,572	1,216,926	489,013
Performance Units Mandatorily Deferred as AEP Career Shares	51,056	52,639	33,501
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	26,337	42,502	6,583
Performance Units to be Paid in Cash	1,019,179	1,121,785	448,929

The cash payouts for the years ended December 31, 2012, 2011 and 2010 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Cash Payouts for Performance Units	$ 44,968	$ 15,985	$ 18,683
Cash Payouts for AEP Career Share Distributions	11,027	2,777	3,594

Restricted Shares and Restricted Stock Units

In 2004, the independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO 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, 66,667 vested on November 30, 2010 and 66,667 vested on November 30, 2011. 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 contractual term for these restricted shares was eight years and dividends on these restricted shares were 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. 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 six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four CEO succession candidates as a retention incentive for 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, 2012, 2011 and 2010 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2012**	**2011**	**2010**
Awarded Units (in thousands)	497	121	873
Weighted Average Grant Date Fair Value	$ 40.69	$ 37.07	$ 35.24

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Restricted Shares and Restricted Stock Units	**2012**	**2011**	**2010**
		(in thousands)	
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 10,608	$ 7,164	$ 6,044
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	12,157	8,017	5,993

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

A summary of the status of our nonvested RSUs as of December 31, 2012 and changes during the year ended December 31, 2012 are as follows:

Nonvested Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Nonvested as of January 1, 2012	903	$ 35.46
Granted	497	40.69
Vested	(306)	34.64
Forfeited	(94)	35.95
Nonvested as of December 31, 2012	1,000	38.22

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2012 was $43 million and the weighted average remaining contractual life was 2.14 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. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested upon grant date. 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 last 20 trading days prior to the distribution date.

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

We had no material cash payouts for stock unit distributions for the years ended December 31, 2012, 2011 and 2010.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2012, 2011 and 2010 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	52	52	54
Weighted Average Grant Date Fair Value	$ 41.20	$ 37.72	$ 34.67

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, 2012, 2011 and 2010 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2012	2011	2010
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 51,767	$ 61,807	$ 28,116
Actual Tax Benefit Realized	18,119	21,632	9,841
Total Compensation Cost Capitalized	10,707	11,608	4,689

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2012, 2011 and 2010, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2012, there was $47 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 1.53 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, 2012, 2011 and 2010 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2012	2011	2010
	(in thousands)		
Cash Received from Stock Options Exercised	$ 3,598	$ 2,855	$ 14,134
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	618	411	706

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 are permitted to 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 our tax withholding obligation.

In February 2013, the HR Committee granted approximately $40 million in share-based awards. This amount will be allocated between 2013-2015 performance units and restricted stock units vesting over 40 months.

15. 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, the power to direct the VIE, variable interests held by related parties and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

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 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, 2012, 2011 and 2010 were $147 million, $128 million and $133 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the 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, 2012, 2011 and 2010 were $32 million, $48 million and $35 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2012, 2011 and 2010 were $127 million, $85 million and $59 million, respectively. 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 respective lease terms, which do not exceed 54 months. 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 the balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides 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 the balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 13.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. 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 $2.3 billion and $1.7 billion as of December 31, 2012 and 2011, respectively, and are included in current and long-term debt on the balance sheets. Transition Funding has securitized transition assets of $2.1 billion and $1.6 billion as of December 31, 2012 and 2011, respectively, which are presented separately on the face of the 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. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

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, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 57	$ 133	$ 130	$ 843	$ 250
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	4	1	2,167 (a)
Total Assets	$ 282	$ 401	$ 134	$ 844	$ 2,417
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 121	$ 43	$ 800	$ 304
Noncurrent Liabilities	250	280	66	1	2,095
Equity	-	-	25	43	18
Total Liabilities and Equity	$ 282	$ 401	$ 134	$ 844	$ 2,417

(a) Includes an intercompany item eliminated in consolidation of $89 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2011
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 48	$ 118	$ 121	$ 910	$ 220
Net Property, Plant and Equipment	154	188	-	-	-
Other Noncurrent Assets	42	118	6	1	1,580
Total Assets	$ 244	$ 424	$ 127	$ 911	$ 1,800
LIABILITIES AND EQUITY					
Current Liabilities	$ 68	$ 103	$ 40	$ 864	$ 229
Noncurrent Liabilities	176	321	71	1	1,557
Equity	-	-	16	46	14
Total Liabilities and Equity	$ 244	$ 424	$ 127	$ 911	$ 1,800

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% 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. SWEPCo's total billings from DHLC for the years ended December 31, 2012, 2011 and 2010 were $77 million, $62 million and $56 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the balance sheets.

Our investment in DHLC was:

	December 31,			
	2012		2011	
	As Reported on the Balance Sheet	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	49	-	52
Total Investment in DHLC	$ 9	$ 58	$ 9	$ 61

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project. The FERC also set the issue of prudency of costs for settlement proceedings.

Our investment in PATH-WV was:

	December 31,			
	2012		2011	
	As Reported on the Balance Sheet	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 19	$ 19
Retained Earnings	12	12	10	10
Total Investment in PATH-WV	$ 31	$ 31	$ 29	$ 29

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. The following tables provide the annual property information:

2012	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	$ 16,973	$ 6,962	1.7 - 3.8 %	31 - 132	$ 9,306	$ 3,526	2.6 - 3.3 %	35 - 66
Transmission	9,846	2,720	1.2 - 2.8 %	25 - 87	-	-	NA	NA
Distribution	15,565	3,837	2.4 - 3.9 %	11 - 75	-	-	NA	NA
CWIP	1,600	(27)	NM	NM	219	1	NM	NM
Other	2,644	1,238	1.8 - 9.6 %	5 - 75	1,301	434	NM	NM
Total	$ 46,628	$ 14,730			$ 10,826	$ 3,961		

2011	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	$ 14,804	$ 6,692	1.6 - 3.8 %	9 - 132	$ 10,134	$ 3,904	2.6 - 3.5 %	20 - 66
Transmission	9,048	2,600	1.3 - 2.7 %	25 - 87	-	-	NA	NA
Distribution	14,783	3,828	2.4 - 4.0 %	11 - 75	-	-	NA	NA
CWIP	2,913 (a)	36	NM	NM	208	1	NM	NM
Other	2,587	1,246	1.7 - 9.3 %	5 - 55	1,193	392	NM	NM
Total	$ 44,135	$ 14,402			$ 11,535	$ 4,297		

2010	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 - 3.8 %	9 - 132	2.2 - 5.1 %	20 - 70
Transmission	1.4 - 3.0 %	25 - 87	NA	NA
Distribution	2.4 - 3.9 %	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	3.0 - 12.5 %	5 - 55	NM	NM

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
NA Not applicable.
NM 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.

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 2012 and 2011 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO as of December 31, 2010	$ 1,398
Accretion Expense	82
Liabilities Incurred	7
Liabilities Settled	(26)
Revisions in Cash Flow Estimates	13
ARO as of December 31, 2011 (a)	1,474
Accretion Expense	85
Liabilities Incurred	17
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	144
ARO as of December 31, 2012	$ 1,696

(a) The current portion of our ARO, totaling $2 million, is included in Other Current Liabilities on our 2011 balance sheet.

As of December 31, 2012 and 2011, our ARO liability was $1.7 billion and $1.5 billion, respectively, and included $1.2 billion and $979 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2012 and 2011, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.4 billion and $1.3 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the 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, 2012	2011	2010
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 93	$ 98	$ 77
Allowance for Borrowed Funds Used During Construction	69	63	53

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 on the statements of income and the investments and accumulated depreciation are reflected on the balance sheets under Property, Plant and Equipment as follows:

			Company's Share as of December 31, 2012		
	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 %	$ -	$ -	$ -
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	310	26	59
J.M. Stuart Generating Station (c)	Coal	26.0 %	542	11	181
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	807	2	387
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2 %	263	8	195
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0 %	121	14	64
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9 %	514	16	371
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3 %	403	4	216
Turk Generating Plant (g)	Coal	73.33 %	1,613	(3)	-
Transmission	NA	(h)	69	4	50
Total			$ 4,642	$ 82	$ 1,523

			Company's Share as of December 31, 2011		
	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 %	310	12	54
J.M. Stuart Generating Station (c)	Coal	26.0 %	529	13	172
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	20	377
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2 %	264	-	193
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0 %	118	6	63
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9 %	513	1	362
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3 %	401	2	208
Turk Generating Plant (g)	Coal	73.33 %	-	1,326	-
Transmission	NA	(h)	63	6	50
Total			$ 2,988	$ 1,386	$ 1,487

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of this unit was impaired in the fourth quarter of 2012. See "Impairments" section of Note 6.
(b) Operated by OPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by CLECO, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Turk Generating Plant was placed in service in December 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 2012, construction costs totaling $457 million have been billed to the other owners.
(h) Varying percentages of ownership.
NA Not applicable.

17. COST REDUCTION PROGRAMS

2012 Sustainable Cost Reductions

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to conduct an organizational and process evaluation and a second firm to evaluate our current employee benefit programs. The process resulted in involuntary severances and is expected to be completed by the end of the first quarter of 2013. 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 during 2012 related to the sustainable cost reductions initiative.

	Total (in millions)
Incurred	$ 47
Settled	(22)
Balance as of December 31, 2012	$ 25

These expenses relate primarily to severance benefits. They are included primarily in Other Operation expense on the statement of income and Other Current Liabilities on the balance sheet. Approximately 95% of the expense was within the Utility Operations segment.

2010 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 was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Many of these eliminated positions resulted from employees that elected retirement through voluntary severance. Most of the affected employees terminated employment as of May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of $293 million to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives.

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 results of operations 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:

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,625	$ 3,551	$ 4,156	$ 3,613
Operating Income	754	741	912	249 (a)(b)
Net Income	390	363	488	21 (a)(b)
Amounts Attributable to AEP Common Shareholders:				
Net Income	389	362	487	21 (a)(b)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05

	2011 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,730	$ 3,609	$ 4,333	$ 3,444
Operating Income	832	717	890 (c)	343 (e)
Income Before Extraordinary Item	355	353	657 (c) (d)	211 (d) (e)
Extraordinary Item, Net of Tax	-	-	273 (d)	100 (d)
Net Income	355	353	930 (c) (d)	311 (d) (e)
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Item	353	352	655 (c) (d)	208 (d) (e)
Extraordinary Item, Net of Tax	-	-	273 (d)	100 (d)
Net Income	353	352	928 (c) (d)	308 (d) (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Item (f)	0.73	0.73	1.35	0.43
Extraordinary Item per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Item (f)	0.73	0.73	1.35	0.43
Extraordinary Item per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63

(a) Includes pretax impairments for certain Ohio generation plants (see Note 6).
(b) See Note 17 for discussion of cost reduction programs in 2012.
(c) Includes pretax plant impairments (see Note 6) and a provision for refund of POLR charges in Ohio.
(d) See "TCC Texas Restructuring" section of Note 2 for discussion of gains recorded in the third and fourth quarters of 2011.
(e) Includes a refund of POLR charges in Ohio and OPCo adjustments for fuel disallowances, the 2010 SEET and the obligation to contribute to Partnership with Ohio and Ohio Growth Fund. Also includes a pretax plant impairment for SWEPCo's Turk Plant (see Note 6).
(f) Quarterly Earnings per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

19. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2012 and 2011 by operating segment are as follows:

	Utility Operations	AEP River Operations	Generation and Marketing	AEP Consolidated
		(in millions)		
Balance as of December 31, 2010	$ 37	$ 39	$ -	$ 76
Impairment Losses	-	-	-	-
Balance as of December 31, 2011	37	39	-	76
Acquired Goodwill	-	-	15	15
Impairment Losses	-	-	-	-
Balance as of December 31, 2012	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2012 and 2011, 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.

During 2012, the increase in goodwill of $15 million was due to the acquisition of BlueStar.

Other Intangible Assets

Acquired intangible assets subject to amortization were $24 million as of December 31, 2012, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. As of December 31, 2011, all acquired intangible assets had been fully amortized. During 2012, as a result of the acquisition of BlueStar, we acquired intangible assets associated with sales contracts and customer accounts of $58 million. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2012		2011	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)			
Easements	10	$ -	$ -	$ 2	$ 2
Purchased Technology	10	-	-	11	11
Acquired Customer Contracts	5	58	34	-	-
Total		$ 58	$ 34	$ 13	$ 13

Amortization of intangible assets was $34 million, $1 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our estimated total amortization is $13 million, $6 million, $3 million and $2 million for 2013, 2014, 2015 and 2016, respectively.

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/buyandmanagestock.

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 February 25, 2013, there were approximately 81,878 registered shareholders and approximately 433,200 shareholders holding stock in street name through a bank or broker. There were 485,790,462 shares outstanding as of February 25, 2013.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2012. 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
Nicholas K. Akins	52	President and Chief Executive Officer
Lisa M. Barton	47	Executive Vice President – Transmission
David M. Feinberg	43	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	52	Senior Vice President and Chief Administrative Officer
Mark C. McCullough	53	Executive Vice President – Generation
Robert P. Powers	58	Executive Vice President and Chief Operating Officer
Brian X. Tierney	45	Executive Vice President and Chief Financial Officer
Dennis E. Welch	61	Executive Vice President and Chief External Officer

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