Appendix A to the
Proxy Statement

American Electric Power

2013 Annual Report

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

AEP: America's Energy Partner®

CONTENTS	AMERICAN ELECTRIC POWER 1 Riverside Plaza Columbus, Ohio 43215-2373

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.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
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.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
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 provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.

Term	Meaning
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI 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.
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, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
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.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
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 which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate 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.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.

Term	Meaning
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
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.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement among APCo, I&M and KPCo.
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 generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
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.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
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 534 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 enacted in 1999 to restructure the electric utility industry in Texas.

Legislation	
TNC	AEP Texas North Company, an AEP electric utility subsidiary.

Term	Meaning
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 coal-fired plant 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 generation capacity and the performance of our generation plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generation 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, cost recovery and/or profitability of our generation 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 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 generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.

- Changes in utility regulation and the allocation of costs within regional transmission organizations, including PJM and SPP.
- The transition to market generation in Ohio, including the implementation of ESPs.
- Our ability to successfully and profitably manage our Ohio generation assets in a startup, nonregulated merchant business.
- 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.

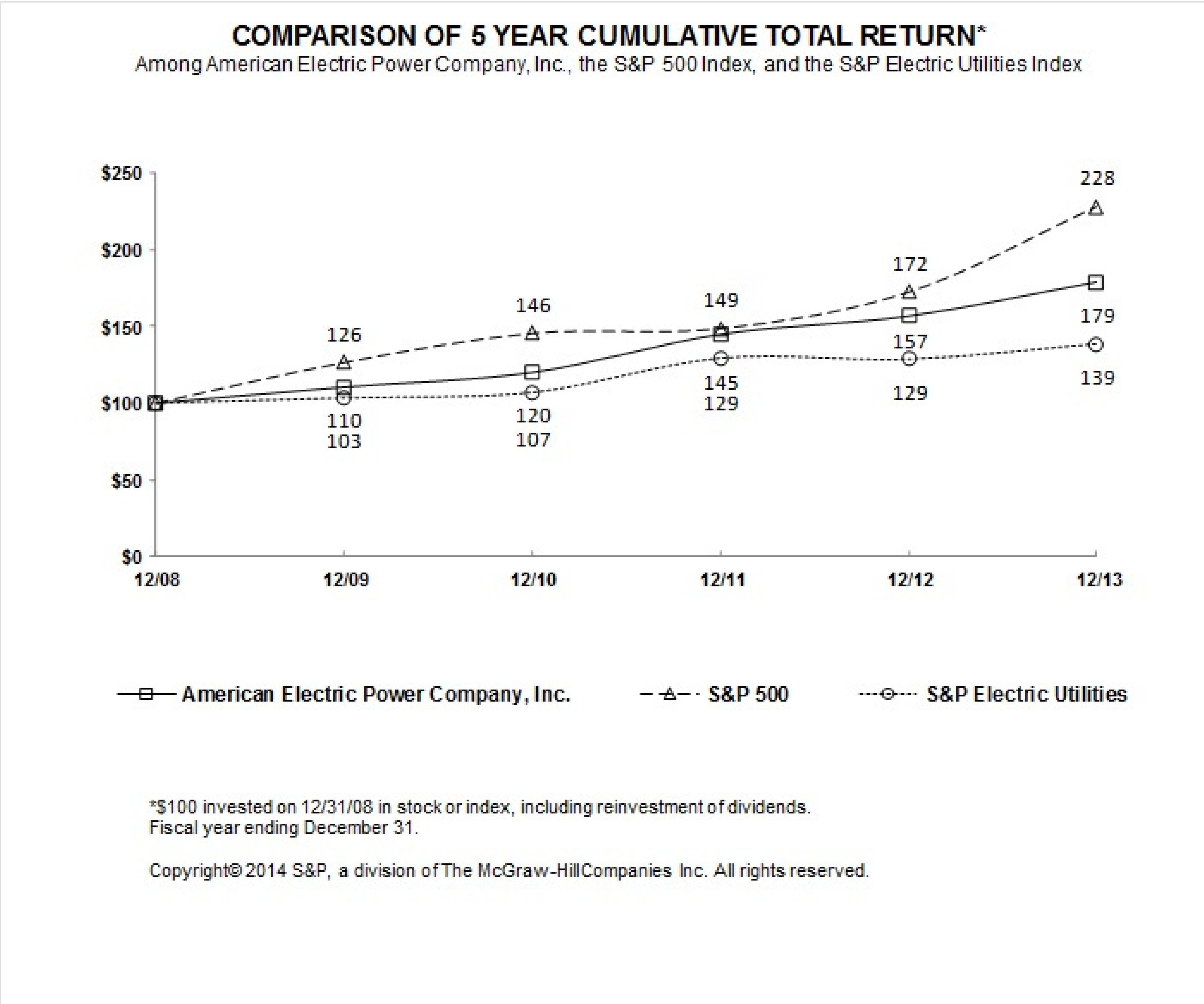
The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, 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, 2013	$ 48.40	$ 43.01	$ 46.74	$ 0.50
September 30, 2013	47.59	41.83	43.35	0.49
June 30, 2013	51.60	42.83	44.78	0.49
March 31, 2013	48.68	42.92	48.63	0.47
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

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2013, AEP had approximately 78,000 registered shareholders.


COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among American Electric Power Company, Inc., the S&P 500 Index, and the S&P Electric Utilities Index
$250
$200
$150
$100
$50
$0
12/08
12/09
12/10
12/11
12/12
12/13
126
146
149
172
228
110
120
145
157
179
103
107
129
129
139
American Electric Power Company, Inc.
S&P 500
S&P Electric Utilities
*$100 invested on 12/31/08 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2013	2012	2011	2010	2009
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 15,357	$ 14,945	$ 15,116	$ 14,427	$ 13,489
Operating Income	$ 2,855	$ 2,656	$ 2,782	$ 2,663	$ 2,771
Income Before Extraordinary Items	$ 1,484	$ 1,262	$ 1,576	$ 1,218	$ 1,370
Extraordinary Items, Net of Tax	-	-	373	-	(5)
Net Income	1,484	1,262	1,949	1,218	1,365
Net Income Attributable to Noncontrolling Interests	4	3	3	4	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,480	1,259	1,946	1,214	1,360
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,480	$ 1,259	$ 1,941	$ 1,211	$ 1,357
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 60,285	$ 57,454	$ 55,670	$ 53,740	$ 51,684
Accumulated Depreciation and Amortization	19,288	18,691	18,699	18,066	17,340
Total Property, Plant and Equipment – Net	$ 40,997	$ 38,763	$ 36,971	$ 35,674	$ 34,344
Total Assets	$ 56,414	$ 54,367	$ 52,223	$ 50,455	$ 48,348
Total AEP Common Shareholders' Equity	$ 16,085	$ 15,237	$ 14,664	$ 13,622	$ 13,140
Noncontrolling Interests	$ 1	$ -	$ 1	$ -	$ -
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ -	$ -	$ 60	$ 61
Long-term Debt (a)	$ 18,377	$ 17,757	$ 16,516	$ 16,811	$ 17,498
Obligations Under Capital Leases (a)	$ 538	$ 449	$ 458	$ 474 (b)	$ 317
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					

Income Before Extraordinary Items	$ 3.04	$ 2.60	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	-	-	0.77	-	(0.01)
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.04	$ 2.60	$ 4.02	$ 2.53	$ 2.96
Weighted Average Number of Basic Shares Outstanding (in millions)	487	485	482	479	459
Market Price Range:					
High	$ 51.60	$ 45.41	$ 41.71	$ 37.94	$ 36.51
Low	$ 41.83	$ 36.97	$ 33.09	$ 28.17	$ 24.00
Year-end Market Price	$ 46.74	$ 42.68	$ 41.31	$ 35.98	$ 34.79
Cash Dividends Declared per AEP Common Share	$ 1.95	$ 1.88	$ 1.85	$ 1.71	$ 1.64
Dividend Payout Ratio	64.14%	72.31%	46.02%	67.59%	55.41%
Book Value per AEP Common Share	$ 32.98	$ 31.35	$ 30.36	$ 28.32	$ 27.49

(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.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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:

- Approximately 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- More than 40,000 miles of transmission lines, including 2,110 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 222,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 5,700 railcars, approximately 3,000 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 37 million tons of coal and dry bulk commodities. Approximately 39% of the barging is for transportation of agricultural products, 26% for coal, 20% for steel and 15% for other commodities.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo will purchase power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo. The transfer of these generation assets and associated liabilities was approved by the FERC, the Virginia SCC and the WVPSC.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Other Impacts of Corporate Separation

In accordance with our December 2010 announcement and our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved the following:

- Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources.
- Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM.
- Power Supply Agreement between AGR and OPCo for AGR to supply capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014.

For a further discussion of corporate separation, see the "Corporate Separation" section of Note 1 and the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters in Note 4.

Ohio Electric Security Plan Filings

2009 – 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover OPCo's deferred fuel costs in rates beginning September 2012. As of December 31, 2013, OPCo's net deferred fuel balance was $445 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo's net deferred fuel costs balance.

June 2012 – May 2015 Ohio 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. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

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 $33/MW day through May 2014 and $148/MW day from June 2014 through May 2015. 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 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is being collected from customers at $3.50/MWh through May 2014 and will be collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of December 31, 2013, OPCo's incurred deferred capacity costs balance was $288 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. OPCo must conduct an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 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. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In December 2013, the PUCO granted applications for rehearing for further consideration filed by OPCo and intervenors. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012-2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC.

Proposed June 2015 – May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the first quarter of 2014.

If OPCo is ultimately not permitted to fully collect its ESP rates including the RSR, and its deferred capacity costs, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 4.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. The reduction in gross margin as a result of customer switching in Ohio is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) RSR collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation & Marketing segment which targets retail customers, both within and outside of our retail service territory.

Customer Demand

In comparison to 2012, our weather-normalized retail sales decreased 1.6% for the year ended December 31, 2013. Our industrial sales declined 4.5% partially due to lower production levels at Ormet, a large aluminum company. Ormet had a contract to purchase power from OPCo through 2018. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down its operations effective immediately. The loss of Ormet's load will not have a material impact on future gross margin. Power previously sold to Ormet will be available to be sold into wholesale markets.

In 2014, we anticipate weather-normalized retail sales will decline by 1.1%. Excluding Ormet, total weather-normalized retail sales are projected to increase by 0.1% in 2014. The largest decline is projected to occur in the industrial class, principally due to Ormet's decision to shut down. Excluding Ormet, the industrial class is projected to grow by 1.2% in 2014, primarily related to a number of new oil and natural gas expansions, especially around the major shale gas areas within AEP's footprint. Weather-normalized residential sales are projected to decline by 0.9% in 2014, continuing the recent trend of declining use per customer related to higher saturations of energy efficient appliances and the promotion of utility sponsored energy efficiency programs. The commercial class energy sales are projected to remain flat compared to 2013.

PJM Capacity Auction

AGR is required to offer all of its available generation in the PJM Reliability Pricing Model (RPM) auction, which is conducted three years in advance of the actual delivery year. Therefore, the majority of AGR generation assets are subject to PJM capacity prices for periods after May 2015. Through May 2015, AGR will provide generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo pays AGR $188.88/MW day. For non-switched OPCo generation customers, OPCo pays AGR for capacity. AGR's non-OPCo load is subject to the PJM RPM auction. Shown below are the current auction prices for capacity, as announced/settled by PJM:

PJM Auction Period	PJM Base Auction Price (per MW day)
June 2013 through May 2014	$ 27.73
June 2014 through May 2015	125.99
June 2015 through May 2016	136.00
June 2016 through May 2017	59.37

We formed a coalition with other utility companies to address mutual concerns related to the PJM capacity auction process, including: (a) import limits for power without firm transmission, (b) placing bidding caps on available demand response resources in comparison to base generation capacity, (c) modification and enforcement of the timing of demand response requirements to better reflect real-time capacity requirements and (d) tightened rules for incremental auctions in which speculative bidders sell resources in the base auction and buy back that capacity in an incremental auction, resulting in no additional capacity and lower market prices. PJM has made three FERC filings related to the first three issues. We anticipate that another filing will be made by PJM later in the first quarter of

2014 to address the fourth issue. In January 2014, FERC accepted without modification PJM's filed recommendations on placing bidding caps on certain demand response products that are available only during the summer period. We expect to receive FERC decisions on the other filings prior to the next RPM auction in May 2014.

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 facility. As of December 31, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.758 billion. As of December 31, 2013, a pretax provision of $59 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total net capitalized expenditures of $1.699 billion.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This Turk Plant output that is currently not subject to cost-based rate recovery and is being sold into the wholesale market. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant or transmission lines, it could reduce future net income and cash flows and impact financial condition. See the "Turk Plant" section of Note 4.

2012 Texas Base Rate Case

In December 2013, the PUCT issued an order granting rehearing and reversed its decision on consolidated tax savings increasing SWEPCo's annual revenues by $5 million. In January 2014, the PUCT determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result of these rulings, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. These rulings also increased SWEPCo's previously approved annual base rates by a total of $13 million. The resulting annual base rate increase is approximately $52 million. See the "Turk Plant" and the "2012 Texas Base Rate Case" sections of Note 4.

2012 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 of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In May 2013, SWEPCo filed testimony in the prudency review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudency review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the "2012 Louisiana Formula Rate Filing" section of Note 4.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of December 31, 2013, SWEPCo has incurred $32 million in costs related to these projects. SWEPCo will seek recovery of costs it incurs from these projects from its state commissions and FERC customers.

2011 Indiana Base Rate Case

In 2013, the IURC issued an order that granted a $92 million annual increase in base rates based upon a return on common equity of 10.2%. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal of the orders with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to certain aspects of the rate case. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows. See the "2011 Indiana Base Rate Case" section of Note 4.

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional types of transmission costs that are expected to increase over the next several years.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost in the application was $285 million, excluding AFUDC to be shared equally between I&M and AEGCo. In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share. As of December 31, 2013, we have incurred costs of $109 million related to the CCT Project, including AFUDC. See the "Rockport Plant Clean Coal Technology Project (CCT Project)" section of Note 4.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the 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 (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON.

If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition. See "Cook Plant Life Cycle Management Project (LCM Project)" section of Note 4.

Repositioning Efforts

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that resulted in sustainable cost savings. This process included evaluations of our employee and retiree benefit programs as well as evaluations of the functional effectiveness and staffing levels of our finance and accounting, information technology, generation and supply chain and procurement organizations. While we have completed certain aspects of this program, our continuous improvement initiatives in generation, distribution, transmission, supply chain, procurement and the corporate center continues to yield cost savings for many of our subsidiaries, allowing us to direct many of these savings into infrastructure and other areas of our business.

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 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss the case, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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, 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. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. 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, 2013, 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 $3 billion to $3.5 billion between 2013 and 2020. These amounts include investments to convert some of our coal generation to natural gas. 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. In addition, we are continuing to evaluate the economic feasibility of environmental investments on nonregulated plants.

Subject to the factors listed above and based upon our continuing evaluation, we intend 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/AGR	Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-4	995
KPCo	Big Sandy Plant, Unit 2	800
AGR	Kammer Plant	630
AGR	Muskingum River Plant, Units 1-5	1,440
AGR	Picway Plant	100
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of December 31, 2013, the net book value of the AGR units listed above was zero. The net book value, before cost of removal, including related material and supplies inventory and CWIP balances of the other plants in the table above was $1 billion. See Note 5 for further discussion.

In 2013, we re-evaluated potential courses of action with respect to the planned operation of Muskingum River Plant, Unit 5 and concluded that completion of a refueling project which would extend the unit's useful life is remote. As a result, in 2013, we completed an impairment analysis and recorded a $154 million pretax ($99 million, net of tax) impairment charge for AGR's net book value of Muskingum River Plant, Unit 5. We expect to retire the plant no later than 2015. See "Muskingum River Plant, Unit 5" section of Note 7.

In addition, we are in the process of obtaining permits and other necessary regulatory approvals for either the conversion of some of our coal units to natural gas or installing emission control equipment on certain units. The following table lists the plants or units that are either awaiting regulatory approval or are still being evaluated by management based on changes in emission requirements and demand for power:

Company	Plant Name and Unit	Generating Capacity
		(in MWs)
KPCo	Big Sandy Plant, Unit 1	278
PSO	Northeastern Station, Unit 3	470
Total		748

As of December 31, 2013, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the plants in the table above was $295 million.

Volatility in natural gas prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that we may close early, we are seeking regulatory recovery of remaining net book values. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially 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 the 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 claims that the AEP subsidiaries violated the NSR provisions of the CAA when it 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 original consent decree required certain types of control equipment to be installed at Muskingum River Plant, Unit 5, Big Sandy Plant, Unit 2 and the two units of the Rockport Plant in 2015, 2017 and 2019, respectively. In January 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the agreement 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 modified consent decree was approved by the court in May 2013. For the units of the Rockport Plant, the modified decree requires installation of dry sorbent injection technology for SO_2 control on both units in 2015. In addition, the consent decree imposes a declining plant-wide cap on SO_2 emissions beginning in 2016.

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. As of December 31, 2013, the net book values of NES, Units 3 and 4 were $208 million and $106 million, respectively, before cost of removal, including materials and supplies inventory and CWIP. In August 2013, the OCC dismissed PSO's environmental compliance plan case without prejudice but will permit PSO to seek recovery in a future proceeding. PSO will address the environmental compliance plan issues in future regulatory proceedings when it seeks cost recovery of the plan. If PSO is ultimately not permitted to fully recover its net book value of NES, Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

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 U.S. 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 2012, a panel of the U.S. 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 CAIR until a replacement rule is finalized. That decision has been appealed to the U.S. Supreme Court. 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 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. 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 U.S. Court of Appeals for the District of Columbia Circuit and its fate is uncertain given 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 has proposed to include CO_2 emissions in standards that apply to new electric utility units and will consider whether such standards are appropriate for other source categories in the future.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2, NO_x and lead, 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 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in 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 U.S. 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 2011, the court granted the motions for stay. In 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" 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 U.S. Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. The petition for further review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. 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 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 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. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of start-up and shut down 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 U.S. 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 briefed and argued, and remains pending before the court.

Regional Haze

In 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 finalized 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 five years of the effective date of the FIP. 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. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement. A revised regional haze SIP was adopted by the State of Oklahoma and the Federal EPA approved the revised SIP in February 2014. Upon publication of the final approval and withdrawal of the FIP, the Tenth Circuit proceeding will be dismissed.

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. New source performance standards affect units that have not yet received permits. The proposed standards were challenged in the U.S. 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.

In June 2013, President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units in September 2013. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO_2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. This proposal was published in the Federal Register in January 2014 and the March 2012 proposal has been withdrawn.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from existing, modified and reconstructed electric generating units before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The President directed the Federal EPA, in developing this proposal, to directly engage states, leaders in the power sector, labor leaders and other stakeholders, to tailor the regulations to reduce costs, to develop market-based instruments and allow regulatory flexibilities and "assure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power." We cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet, but the costs may be substantial.

In June 2012, the U.S. 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. The U.S. Supreme Court granted several petitions for review and will determine whether the Federal EPA made a reasonable determination that adoption of the motor vehicle standards trigger PSD and Title V permitting obligations for stationary sources. A decision is expected by June 2014.

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 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. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of items.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and sought 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. In October 2013, the U.S. District Court for the District of Columbia issued a final order partially ruling in favor of the Federal EPA for dismissal of two counts, ruling in favor of the environmental organizations on one count and directing the Federal EPA to provide the court with a proposed schedule for completion of the rulemaking. In January 2014, the parties filed a motion with the court to establish December 2014 as the Federal EPA's deadline for publication of the rule. The court will establish a deadline for the final rule following a comment period for interested parties.

In February 2014, the Federal EPA completed an evaluation of the beneficial uses of coal fly ash in concrete and wallboard and concluded that the Federal EPA supports these beneficial uses. 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 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 expected in 2014. 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 was signed in April 2013 with a final rule expected in 2014. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of our long-term plans. We continue to review the proposal in detail to evaluate whether our plants are currently meeting the proposed limitations, what technologies have been incorporated into our long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. We submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which we are members.

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.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We estimate that our 2013 emissions were approximately 115 million metric tons. This represents a reduction of 21% compared to our 2005 CO_2 emissions of approximately 145 million metric tons.

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 Vertically Integrated Utilities 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.

During the fourth quarter of 2013, we realigned our business segments as a result of corporate separation and plant transfers. We retrospectively adjusted 2012 and 2011 segment information to reflect our new business segments. See the "Corporate Separation" section of Executive Overview.

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

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

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

AEP Transmission Holdco

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

AEP River Operations

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

The table below presents Income Before Extraordinary Item by segment for the years ended December 31, 2013, 2012 and 2011.

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Vertically Integrated Utilities	$ 681	$ 803	$ 710

Transmission and Distribution Utilities	358	389	404
Generation & Marketing	228	100	439
AEP Transmission Holdco	80	43	30
AEP River Operations	12	15	45
Corporate and Other (a)	125	(88)	(52)
Income Before Extraordinary Item	$ 1,484	$ 1,262	$ 1,576

(a) While not considered a reportable segment, Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

AEP CONSOLIDATED

2013 Compared to 2012

Income Before Extraordinary Item increased from $1,262 million in 2012 to $1,484 million in 2013 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- 2012 impairments of certain Ohio generation plants.
- A decrease in Ohio depreciation expense due to impairments of certain Ohio generation plants.
- A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

These increases were partially offset by:

- Impairments during 2013 for the following:
  - Muskingum River Plant, Unit 5.
  - A write-off from a disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- The loss of retail generation customers in Ohio to various CRES providers.
- 2012 reversal of a 2011 recorded 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.

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.
- 2012 impairments of certain Ohio generation plants.
- The loss of retail generation 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 U.K. Windfall Tax provision as a result of a 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.

Our results of operations are discussed below by operating segment.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 9,992	$ 9,418	$ 9,702
Fuel and Purchased Electricity	4,770	4,408	4,870
Gross Margin	5,222	5,010	4,832
Other Operation and Maintenance	2,276	2,219	2,237
Asset Impairments and Other Related Charges	72	13	49
Depreciation and Amortization	941	873	785
Taxes Other Than Income Taxes	372	344	339
Operating Income	1,561	1,561	1,422
Interest and Investment Income	7	5	13
Carrying Costs Income	14	28	17
Allowance for Equity Funds Used During Construction	35	72	82
Interest Expense	(540)	(520)	(514)
Income Before Income Tax Expense and Equity Earnings	1,077	1,146	1,020
Income Tax Expense	398	345	312
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Income Before Extraordinary Item	$ 681	$ 803	$ 710

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31, 2013	2012	2011
	(in millions of KWhs)		
Retail:			
Residential	33,851	33,199	35,135
Commercial	25,037	25,278	25,651
Industrial	34,216	34,692	34,333
Miscellaneous	2,284	2,356	2,349
Total Retail	95,388	95,525	97,468
Wholesale	31,919	28,671	28,290
Total KWhs	127,307	124,196	125,758

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 Vertically Integrated Utilities

	Years Ended December 31,		
	2013	**2012**	**2011**
	(in degree days)		
Eastern Region			
Actual - Heating (a)	2,949	2,216	2,566
Normal - Heating (b)	2,734	2,774	2,772
Actual - Cooling (c)	1,040	1,253	1,280
Normal - Cooling (b)	1,080	1,079	1,066
Western Region			
Actual - Heating (a)	1,772	1,070	1,582
Normal - Heating (b)	1,501	1,537	1,534
Actual - Cooling (c)	2,163	2,635	2,830
Normal - Cooling (b)	2,202	2,186	2,165

(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 and Western Region cooling degree days are calculated on a 65 degree temperature base.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Vertically Integrated Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$ 803
Changes in Gross Margin:	
Retail Margins	196
Off-system Sales	(26)
Transmission Revenues	41
Other Revenues	1
Total Change in Gross Margin	212
Changes in Expenses and Other:	
Other Operation and Maintenance	(57)
Asset Impairments and Other Related Charges	(59)
Depreciation and Amortization	(68)
Taxes Other Than Income Taxes	(28)
Interest and Investment Income	2
Carrying Costs Income	(14)
Allowance for Equity Funds Used During Construction	(37)
Interest Expense	(20)
Total Change in Expenses and Other	(281)
Income Tax Expense	(53)
Year Ended December 31, 2013	$ 681

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 $196 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $153 million rate increase for SWEPCo.
    - A $112 million rate increase for I&M.
    - A $9 million rate increase for APCo.

      For the rate increases described above, $42 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $29 million increase in weather-related usage in our eastern and western regions primarily due to increases of 33% and 66%, respectively, in heating degree days partially offset by decreases in our eastern and western regions of 17% and 18%, respectively, in cooling degree days.

  These increases were partially offset by:
  - A $15 million decrease in SWEPCo's municipal and cooperative revenues primarily due to lower realizations from changes in sales volume mix.
  - A $23 million decrease due to lower weather normalized retail sales.
  - A $12 million increase in other variable electric generation expenses.

- A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of the June 2012 Virginia SCC fuel factor order.
- A $9 million decrease 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.

- **Margins from Off-system Sales** decreased $26 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins, partially offset by higher prices and volumes.
- **Transmission Revenues** increased $41 million primarily due to increased investment in the PJM and SPP regions. These increased revenues are offset-in-part in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $57 million primarily due to the following:
  - A $33 million increase in recoverable PJM and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers.
  - A $30 million write-off in 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $22 million increase in storm-related expenses primarily in APCo's service territory.
  - A $21 million increase in plant outage expenses.

  These increases were partially offset by:
  - A $26 million decrease due to expenses related to the 2012 sustainable cost reductions.
  - A $25 million decrease due to an agreement reached to settle an insurance claim in 2013.
- **Asset Impairments and Other Related Charges** increased $59 million primarily due to the following:
  - A $39 million increase due to APCo's 2013 write-off from a regulatory disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order approving the transfer of Amos Plant, Unit 3.
  - A $33 million increase due to KPCo's 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with a KPSC's October 2013 order.

  These increases were partially offset by:
  - 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.
- **Depreciation and Amortization** expenses increased $68 million primarily due to the following:
  - A $40 million increase due to the Turk Plant being placed in service in December 2012.
  - A $26 million increase due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life approved by the MPSC effective April 2012 and by the IURC effective March 2013. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $13 million decrease in amortization as a result of the cessation of the Virginia Environmental and Reliability surcharge and the Virginia Environmental Rate Adjustment Clause in January 2013 and March 2013, respectively.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to increased property taxes as a result of increased capital investments.
- **Carrying Costs Income** decreased $14 million primarily due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in late January 2012 and decreased carrying charges related to the Dresden Plant.
- **Allowance for Equity Funds Used During Construction** decreased $37 million primarily due to completed construction of the Turk Plant in December 2012.
- **Interest Expense** increased $20 million primarily due to a decrease in the debt component of AFUDC due to completed construction of the Turk Plant in December 2012 partially offset by lower average outstanding long-term debt balances and an increase in the debt component of AFUDC related to projects at the Cook Plant.
- **Income Tax Expense** increased $53 million primarily due to the recording of federal and state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, offset-in-part by a decrease in pretax book income.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Vertically Integrated Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$ 710
Changes in Gross Margin:	
Retail Margins	181
Off-system Sales	(13)
Transmission Revenues	19
Other Revenues	(9)
Total Change in Gross Margin	178
Changes in Expenses and Other:	
Other Operation and Maintenance	18
Asset Impairments and Other Related Charges	36
Depreciation and Amortization	(88)
Taxes Other Than Income Taxes	(5)
Interest and Investment Income	(8)
Carrying Costs Income	11
Allowance for Equity Funds Used During Construction	(10)
Interest Expense	(6)
Total Change in Expenses and Other	(52)
Income Tax Expense	(33)
Year Ended December 31, 2012	$ 803

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 $181 million primarily due to the following:
  - A $130 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sport Plant, Unit 5 from the Interconnection Agreement in September 2011.
  - Successful rate proceedings in our service territories which include:
    - 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, $99 million relates to riders/trackers which have corresponding increases in other expense items below.
  - 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 a November 2011 Virginia SCC order.

- A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of a 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 $71 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 14% and 32%, respectively, in heating degree days and a 7% decrease in cooling degree days in our western region.

- **Margins from Off-system Sales** decreased $13 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins and lower power prices.
- **Transmission Revenues** increased $19 million primarily due to increased investment in the PJM region. These increased revenues are offset-in-part in Other Operation and Maintenance expenses below.
- **Other Revenues** decreased $9 million primarily due to a decrease in miscellaneous sales partially offset by a 2011 unfavorable provision for refund of outage insurance proceeds.

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

- **Other Operation and Maintenance** expenses decreased $18 million primarily due to the following:
  - A $46 million decrease in plant outage and other plant operating and maintenance expenses.
  - 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 $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 $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 $26 million increase due to expenses related to the 2012 sustainable cost reductions.
- **Asset Impairments and Other Related Charges** decreased $36 million due to the 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 a November 2011 Texas Court of Appeals decision. This was partially offset by the 2012 write-off of an additional $13 million related to SWEPCo's Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $88 million primarily due to the following:
  - 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.
  - Overall higher depreciable property balances.
- **Carrying Costs Income** increased $11 million due to adjustments for disallowed environmental costs as approved in a November 2011 Virginia SCC order and 2012 adjustments for certain costs subsequently determined by the Supreme Court of Virginia to be appropriate for recovery.
- **Allowance for Equity Funds Used During Construction** decreased $10 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.
- **Income Tax Expense** increased $33 million primarily due to an increase in pretax book income offset-in-part by the recording of federal and state income tax adjustments.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 4,478	$ 4,819	$ 5,156
Purchased Electricity	1,627	2,072	2,711
Gross Margin	2,851	2,747	2,445
Other Operation and Maintenance	1,003	911	954
Depreciation and Amortization	591	561	549
Taxes Other Than Income Taxes	435	428	417
Operating Income	822	847	525
Interest and Investment Income	2	4	7
Carrying Costs Income	16	24	375
Allowance for Equity Funds Used During Construction	8	6	9
Interest Expense	(292)	(291)	(293)
Income Before Income Tax Expense	556	590	623
Income Tax Expense	198	201	219
Income Before Extraordinary Item	$ 358	$ 389	$ 404

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2013	2012	2011
	(in millions of KWhs)		
Retail:			
Residential	25,531	25,581	26,520
Commercial	24,631	24,746	25,116
Industrial	22,668	24,902	25,334
Miscellaneous	710	716	751
Total Retail (a)	73,540	75,945	77,721
Wholesale	8	8	8
Total KWhs	73,548	75,953	77,729

(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 Transmission and Distribution Utilities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in degree days)	
Eastern Region			
Actual - Heating (a)	3,383	2,610	3,107
Normal - Heating (b)	3,229	3,276	3,266
Actual - Cooling (c)	1,029	1,248	1,112
Normal - Cooling (b)	954	948	936
Western Region			
Actual - Heating (a)	368	177	394
Normal - Heating (b)	337	352	351
Actual - Cooling (d)	2,737	3,100	3,242
Normal - Cooling (b)	2,608	2,584	2,557

(a) 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 70 degree temperature base.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Transmission and Distribution Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$	389
Changes in Gross Margin:		
Retail Margins		55
Off-System Sales		1
Transmission Revenues		46
Other Revenues		2
Total Change in Gross Margin		104
Changes in Expenses and Other:		
Other Operation and Maintenance		(92)
Depreciation and Amortization		(30)
Taxes Other Than Income Taxes		(7)
Interest and Investment Income		(2)
Carrying Costs Income		(8)
Allowance for Equity Funds Used During Construction		2
Interest Expense		(1)
Total Change in Expenses and Other		(138)
Income Tax Expense		3
Year Ended December 31, 2013	$	358

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity were as follows:

- **Retail Margins** increased $55 million primarily due to the following:
  - A $123 million increase in revenues associated with OPCo's Universal Service Fund (USF) surcharge and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $17 million increase related to favorable regulatory proceedings for OPCo.

  These increases were partially offset by:
  - A $40 million decrease related 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 $35 million decrease due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.
- **Transmission Revenues** increased $46 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.

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

Other Operation and Maintenance expenses increased $92 million primarily due to the following:

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- An \$86 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in retail margins above.
- A \$30 million net increase related to the 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 and the PUCO's August 2012 approval of the June 2012-May 2015 ESP.

These increases were partially offset by:

- A \$14 million decrease in expenses related to the 2012 sustainable cost reductions.
- A \$13 million decrease in Ohio's *gridSMART®* expenses primarily due to a reduction in the operation

and maintenance component of the *gridSMART*® rider for prior years' over collections. This decrease was partially offset by a corresponding increase in Depreciation and Amortization.

- **Depreciation and Amortization** expenses increased $30 million primarily due to the following:
  - An $8 million increase due to OPCo's and TCC's issuance of securitization bonds in August 2013 and March 2012, respectively. This increase in OPCo's and TCC's securitization related amortizations are offset within Gross Margin.
  - A $7 million increase due to increased investment in distribution and transmission plant.
  - A $4 million increase in Ohio's *gridSMART*® expenses primarily due to an increase in the depreciation component of the *gridSMART*® rider to recover prior years' under collections. This increase was offset by a corresponding decrease in operation and maintenance expense above.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $8 million primarily due to the first quarter 2012 recording of debt carrying costs prior to TCC's issuance of securitization bonds in March 2012.
- **Income Tax Expense** decreased $3 million primarily due to a decrease in pretax book income offset-in-part by the recording of state income tax adjustments.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Transmission and Distribution Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$ 404
Changes in Gross Margin:	
Retail Margins	192
Transmission Revenues	59
Other Revenues	51
Total Change in Gross Margin	302
Changes in Expenses and Other:	
Other Operation and Maintenance	43
Depreciation and Amortization	(12)
Taxes Other Than Income Taxes	(11)
Interest and Investment Income	(3)
Carrying Costs Income	(351)
Allowance for Equity Funds Used During Construction	(3)
Interest Expense	2
Total Change in Expenses and Other	(335)
Income Tax Expense	18
Year Ended December 31, 2012	$ 389

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity were as follows:

- **Retail Margins** increased $192 million primarily due to the following:
  - A $156 million increase in revenues primarily associated with OPCo's Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $35 million increase due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.

  These increases were partially offset by:
  - A $46 million decrease related 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.
- **Transmission Revenues** increased $59 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.
- **Other Revenues** increased $51 million primarily due to 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 $43 million primarily due to the following:
  - 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.

  These decreases were partially offset by:
  - A $13 million increase in storm-related expenses primarily in Ohio.
  - A $13 million increase due to expenses related to the 2012 sustainable cost reductions.
- **Depreciation and Amortization** expenses increased $12 million primarily due to the following :
  - 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.

- An $11 million increase in amortization of 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.
- A $9 million increase due to higher depreciable property balances primarily related to the Texas Automated Meter Infrastructure project.

These increases were partially offset by:

- A $39 million decrease due to amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
- A $23 million decrease due to 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.

- **Taxes Other Than Income Taxes** increased $11 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $351 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.
- **Income Tax Expense** decreased $18 million primarily due to a decrease in pretax book income and by the recording of state income tax adjustments.

GENERATION & MARKETING

Generation & Marketing	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 3,665	$ 3,467	$ 3,894
Fuel, Purchased Electricity and Other	2,305	2,065	2,215
Gross Margin	1,360	1,402	1,679
Other Operation and Maintenance	523	507	537
Asset Impairments and Other Related Charges	154	287	90
Depreciation and Amortization	236	349	304
Taxes Other Than Income Taxes	54	62	60
Operating Income	393	197	688
Interest and Investment Income	2	1	4
Interest Expense	(55)	(83)	(87)
Income Before Income Tax Expense	340	115	605
Income Tax Expense	112	15	166
Income Before Extraordinary Item	$ 228	$ 100	$ 439

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2013	2012	2011
	(in millions of MWhs)		
Fuel Type:			
Coal	38	37	45
Natural Gas	6	11	7
Wind	1	1	1
Total MWhs	45	49	53

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Generation & Marketing Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$ 100
Changes in Gross Margin:	
Generation	(44)
Retail, Trading and Marketing	4
Other	(2)
Total Change in Gross Margin	(42)
Changes in Expenses and Other:	
Other Operation and Maintenance	(16)
Asset Impairments and Other Related Charges	133
Depreciation and Amortization	113
Taxes Other Than Income Taxes	8
Interest and Investment Income	1
Interest Expense	28
Total Change in Expenses and Other	267
Income Tax Expense	(97)
Year Ended December 31, 2013	$ 228

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, purchased electricity and certain costs of service for retail operations were as follows:

- **Generation** decreased $44 million primarily due to the following:
  - A $336 million decrease in affiliated sales to OPCo primarily due to customers switching to alternative CRES providers as well as a reduction in industrial usage.

  This decrease was partially offset by the following:
  - A $221 million net increase in sales to AEP affiliates under the Interconnection Agreement.
  - A $63 million decrease in fuel expenses due to a reduction in generation at the Lawrenceburg Plant.

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

- **Other Operation and Maintenance** expenses increased $16 million primarily due to a 2013 adjustment of $14 million to impaired plant investment as a result of changes to asset retirement obligations for asbestos removal and retirement of ash disposal facilities at impaired plants.
- **Asset Impairments and Other Related Charges** decreased $133 million 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.

  This decrease was partially offset by:
  - A 2013 impairment of $154 million for Muskingum River Plant, Unit 5.

- **Depreciation and Amortization** expenses decreased $113 million primarily due to depreciation ceasing on certain Ohio generation plants that were impaired in November 2012 and June 2013.
- **Interest Expense** decreased $28 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $97 million primarily due to an increase in pretax book income and by the recording of state income tax adjustments.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Generation & Marketing Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$ 439
Changes in Gross Margin:	
Generation	(363)
Retail, Trading and Marketing	86
Total Change in Gross Margin	(277)
Changes in Expenses and Other:	
Other Operation and Maintenance	30
Asset Impairments and Other Related Charges	(197)
Depreciation and Amortization	(45)
Taxes Other Than Income Taxes	(2)
Interest and Investment Income	(3)
Interest Expense	4
Total Change in Expenses and Other	(213)
Income Tax Expense	151
Year Ended December 31, 2012	$ 100

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, purchased electricity and certain costs of service for retail operations were as follows:

- **Generation** decreased $363 million primarily due to the following:
  - A $396 million decrease in affiliated sales to OPCo primarily due to customer switching to alternative CRES providers.

  This decrease was partially offset by:
  - A $29 million increase in non-affiliated sales due to increased sales to Buckeye Power, Inc. for back-up energy under the Cardinal Station Agreement.
- **Retail, Trading and Marketing** increased $86 million primarily due to the March 2012 acquisition of BlueStar.

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

- **Other Operation and Maintenance** expenses decreased $30 million primarily due to the following:
  - A $78 million decrease in plant outage and other plant operating and maintenance expenses.

  This decrease was partially offset by:
  - A $47 million increase in AEP Energy labor and sales expenses due to the acquisition of BlueStar in March 2012.
- **Asset Impairments and Other Related Charges** increased $197 million 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.

This increase was partially offset by:

- 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 $45 million primarily due to the following:
  - A $58 million increase due to shortened depreciable lives for certain AGR generation plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $13 million decrease in depreciation due to the 2011 plant impairment of Sporn Plant, Unit 5.
- **Income Tax Expense** decreased $151 million primarily due to a decrease in pretax book income.

AEP TRANSMISSION HOLDCO

2013 Compared to 2012

Income Before Extraordinary Item from our AEP Transmission Holdco segment increased from $43 million in 2012 to $80 million in 2013 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

2012 Compared to 2011

Income Before Extraordinary Item from our AEP Transmission Holdco 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.

AEP RIVER OPERATIONS

2013 Compared to 2012

Income Before Extraordinary Item from our AEP River Operations segment decreased from $15 million in 2012 to $12 million in 2013 primarily due to significant reductions in export grain and coal demand. In addition, low water levels in the first and fourth quarters of 2013 limited barge loads and tow sizes.

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.

CORPORATE AND OTHER

2013 Compared to 2012

Income Before Extraordinary Item from Corporate and Other increased from a loss of $88 million in 2012 to income of $125 million in 2013 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013 as well as a reduction in interest expense associated with the early retirement of debt in 2012.

2012 Compared to 2011

Income Before Extraordinary Item from Corporate and Other decreased from a loss of $52 million in 2011 to a loss of $88 million in 2012 primarily due to costs associated with the early retirement of debt in 2012 and the 2012 adjustment of a U.K. Windfall Tax provision as a result of a related Supreme Court case, partially offset by a loss incurred in 2011 related to the settlement of litigation with BOA and Enron.

AEP SYSTEM INCOME TAXES

2013 Compared to 2012

Income Tax Expense increased $80 million primarily due to an increase in pretax book income and the recording of state income tax adjustments partially offset by a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

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.

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,					
	2013			2012		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$	18,377	52.2 %	$	17,757	52.3 %
Short-term Debt		757	2.1		981	2.9
Total Debt		19,134	54.3		18,738	55.2
AEP Common Equity		16,085	45.7		15,237	44.8
Noncontrolling Interests		1	-		-	-
Total Debt and Equity Capitalization	$	35,220	100.0 %	$	33,975	100.0 %

Our ratio of debt-to-total capital decreased from 55.2% as of December 31, 2012 to 54.3% as of December 31, 2013 primarily due to an increase in common equity, partially offset by a net increase in debt issuances, including the issuance of $647 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, 2013, we had $3.5 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.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of December 31, 2013, our available liquidity was approximately $3.4 billion as illustrated in the table below:

	Amount		Maturity
	(in millions)		
Commercial Paper Backup:			
Revolving Credit Facility	$	1,750	June 2016
Revolving Credit Facility		1,750	July 2017
Total		3,500	
Cash and Cash Equivalents		118	
Total Liquidity Sources		3,618	
Less: AEP Commercial Paper Outstanding		57	

Letters of Credit Issued	170
Net Available Liquidity	$ 3,391

We have credit facilities totaling $3.5 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.2 billion.

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 2013 was $904 million. The weighted-average interest rate for our commercial paper during 2013 was 0.32%.

Other Credit Facilities

In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate OPCo's corporate separation of generation assets from transmission and distribution. As of December 31, 2013, the $1 billion term credit facility was entirely drawn. Repayments prior to maturity are permitted. However, any amount that is repaid may not be re-borrowed and is a permanent reduction of the term credit facility.

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility signed in October 2013. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Financing Plan

As of December 31, 2013, we have $1.5 billion of long-term debt due within one year which includes $879 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 $413 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 2013, we amended our receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014 and the remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

West Virginia Securitization of Regulatory Assets

In September 2013, the WVPSC approved a settlement agreement filed by APCo, WPCo and intervenors which authorized APCo to securitize $376 million, plus upfront financing costs, related primarily to the December 2011 under-recovered Expanded Net Energy Charge (ENEC) deferral balance. In November 2013, APCo issued $380 million of Securitization Bonds to securitize the under-recovered ENEC deferral balance, including $4 million of upfront financing costs, with a final maturity date of August 2031. APCo implemented a new securitization rider which was offset by an equal reduction in ENEC revenues, with no overall change in total revenues.

Ohio Securitization of Regulatory Assets

In March 2013, the PUCO approved OPCo's request to securitize the Deferred Asset Recovery Rider (DARR) balance. In August 2013, OPCo issued $267 million of Securitization Bonds, with a final maturity date of July 2020, to securitize the DARR balance. As a result of the securitization, recovery through the DARR has ceased and has been replaced by the Deferred Asset Phase-in Rider which will recover the securitized assets.

Debt Covenants and Borrowing Limitations

Our 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 credit agreements. Debt as defined in the credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2013, this contractually-defined percentage was 50.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of

December 31, 2013, 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. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow 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 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, 2013, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.50 per share in January 2014. 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. However, we do not believe these restrictions 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,		
	2013	**2012**	**2011**
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 279	$ 221	$ 294
Net Cash Flows from Operating Activities	4,106	3,804	3,788
Net Cash Flows Used for Investing Activities	(3,818)	(3,391)	(2,890)
Net Cash Flows Used for Financing Activities	(449)	(355)	(971)
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	58	(73)
Cash and Cash Equivalents at End of Period	$ 118	$ 279	$ 221

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,		
	2013	2012	2011
		(in millions)	
Net Income	$ 1,484	$ 1,262	$ 1,949
Depreciation and Amortization	1,743	1,782	1,655
Other	879	760	184
Net Cash Flows from Operating Activities	$ 4,106	$ 3,804	$ 3,788

Net Cash Flows from Operating Activities were $4.1 billion in 2013 consisting primarily of Net Income of $1.5 billion, $1.7 billion of noncash Depreciation and Amortization and $226 million of Asset Impairments related to Muskingum River Plant, Unit 5, Big Sandy and Amos Plants, partially offset by $214 million of Ohio capacity deferrals as a result of a 2012 PUCO order. 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. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax versus book temporary differences from operations. Significant changes in other items include the favorable impact of a decrease in fuel inventory and net cash flows for Accrued Taxes as a result of the recognition of the tax benefit related to the U.K. Windfall Tax.

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.

Investing Activities

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Construction Expenditures	$ (3,624)	$ (3,025)	$ (2,669)
Acquisitions of Nuclear Fuel	(154)	(107)	(106)
Acquisitions of Assets/Businesses	(32)	(94)	(19)
Acquisitions of Cushion Gas from BOA	-	-	(214)
Proceeds from Sales of Assets	21	18	123
Other	(29)	(183)	(5)
Net Cash Flows Used for Investing Activities	$ (3,818)	$ (3,391)	$ (2,890)

Net Cash Flows Used for Investing Activities were $3.8 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

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.

Financing Activities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Issuance of Common Stock, Net	$ 84	$ 83	$ 92
Issuance/Retirement of Debt, Net	385	544	(33)
Proceeds from Nuclear Fuel Sale/Leaseback	110	-	-
Retirement of Cumulative Preferred Stock	-	-	(64)
Dividends Paid on Common Stock	(954)	(916)	(898)
Other	(74)	(66)	(68)
Net Cash Flows Used for Financing Activities	$ (449)	$ (355)	$ (971)

Net Cash Flows Used for Financing Activities in 2013 were $449 million. Our net debt issuances were $385 million. The net issuances included issuances of $745 million of senior unsecured notes, $1 billion draws on a $1 billion term credit facility, $647 million of securitization bonds, $328 million of notes payable and other debt and $305 million of pollution control bonds offset by retirements of $1.8 billion of senior unsecured and other debt notes, $331 million of pollution control bonds, $243 million of securitization bonds and a decrease in short-term borrowing of $224 million. We paid common stock dividends of $954 million. See Note 14 – Financing Activities.

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.

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.

The following financing activities occurred during 2013:

AEP Common Stock:

- During 2013, we issued 2.1 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $84 million.

Debt:

- During 2013, we issued approximately $3 billion of long-term debt, including $1 billion drawn on a term credit facility, $745 million of senior notes at interest rates ranging from 2.73% to 5.32% and $647 million of securitization bonds at interest rates ranging from 0.96% to 3.77%. We also issued $190 million of pollution control revenue bonds at interest rates ranging from 3.25% to 4%, $115 million of pollution control revenue bonds at variable interest rates and $328 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 2013, we entered no interest rate derivatives and settled $379 million of such transactions. The settlements resulted in net cash payments of $26 million. As of December 31, 2013, we had in place $820 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2014:

- In January 2014, TCC retired $112 million of Securitization Bonds.
- In January and February 2014, I&M retired $24 million of Notes Payable related to DCC Fuel.
- In January 2014, OPCo retired $225 million of 4.85% Senior Unsecured Notes due in 2014.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.8 billion of construction expenditures excluding equity AFUDC for 2014. For 2015 and 2016, we forecast construction expenditures of $3.8 billion each year. The expenditures are generally for transmission, distribution and required environmental investment to comply with Federal EPA rules. 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 2014 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2014 Budgeted Construction Expenditures					
Segment	**Environmental**	**Generation**	**Transmission**	**Distribution**	**Other**	**Total**
			(in millions)			
Vertically Integrated Utilities	$ 467	$ 410	$ 465	$ 564	$ 67	$ 1,973
Transmission and Distribution Utilities	7	5	340	494	36	882
Generation & Marketing	114	63	-	-	14	191

AEP Transmission Holdco	-	-	786	-	1	787
AEP River Operations	-	-	-	-	9	9
Corporate and Other	-	-	-	-	3	3
Total	$ 588	$ 478	$ 1,591	$ 1,058	$ 130	$ 3,845

OFF-BALANCE SHEET ARRANGEMENTS

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 $665 million and $665 million, respectively, as of December 31, 2013.

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

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $28 million for the remaining railcars as of December 31, 2013. 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, 2013, the maximum potential loss was approximately $19 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, 2013:

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)	$ 757	$ -	$ -	$ -	$ 757
Interest on Fixed Rate Portion of Long-term Debt (b)	784	1,442	1,250	6,283	9,759
Fixed Rate Portion of Long-term Debt (c)	988	2,284	2,853	10,328	16,453
Variable Rate Portion of Long-term Debt (d)	561	1,382	6	-	1,949
Capital Lease Obligations (e)	135	208	123	215	681
Noncancelable Operating Leases (e)	288	514	445	862	2,109
Fuel Purchase Contracts (f)	2,362	3,391	2,235	2,649	10,637
Energy and Capacity Purchase Contracts	195	410	457	2,634	3,696
Construction Contracts for Capital Assets (g)	807	1,123	931	1,797	4,658
Total	$ 6,877	$ 10,754	$ 8,300	$ 24,768	$ 50,699

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See “Long-term Debt” section of Note 14. Represents principal only excluding interest.
(d) See “Long-term Debt” section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.02% and 1.91% as of December 31, 2013.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents 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 $51 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, 2013, we expect to make contributions to our pension plans totaling $80 million in 2014. Estimated contributions of $78 million in 2015 and $84 million in 2016 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the accumulated benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 99.9% funded as of December 31, 2013.

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, 2013, 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)	$ 170	$ -	$ -	$ -	$ 170
Guarantees of the Performance of Outside Parties (b)	-	-	-	115	115
Guarantees of Our Performance (c)	592	-	10	58	660
Total Commercial Commitments	$ 762	$ -	$ 10	$ 173	$ 945

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as natural 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 $170 million with maturities ranging from February 2014 to April 2015. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

<u>SIGNIFICANT TAX LEGISLATION</u>

The Small Business Jobs Act extended the time for claiming bonus depreciation and increased the deduction to 100% for 2011 and decreased 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 or financial condition but did have a favorable impact on cash flows in 2013.

<u>CYBER SECURITY</u>

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, investors and 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 is being developed through this executive order will be reviewed by the FERC and the U.S. Department of Energy. We are participating in the process by submitting feedback through our industry trade group and sharing best practices already in place. We protect our critical cyber assets, such as our data centers, power plants, 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 additional steps to enhance our capabilities for identifying risks or threats and have shared those threats with our utility peers, industry and federal agencies. We operate our own Cyber Security Operations Center. Funding for this included a grant from the American Recovery and Reinvestment Act – U.S. Department of Energy Smart Grid Demonstration Program. This facility was initially designed as a pilot cyber threat and information-sharing center specifically for the electric sector and today is fully operational.

In 2013, as part of our industry's continuing program to advance threat sharing and coordination, we participated in the North American Electric Reliability Corporation (NERC) GridEx II exercise. This effort, led by NERC, tested and developed the coordination and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

In 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. We are working with the U.S. Department of Energy on several projects covering advanced cyber security and assessment tools.

We have partnered with a major defense contractor who has significant cyber security experience and technical capabilities 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. We continue to work with a nonaffiliated entity to conduct several seminars each year about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect ourselves while helping our industry advance its cyber security capabilities.

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 5 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 Vertically Integrated Utilities segment were $(9) million, $13 million and $(57) million for the years ended December 31, 2013, 2012 and 2011, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Vertically Integrated Utilities segment were $283 million and $292 million as of December 31, 2013 and 2012, respectively.

The changes in unbilled electric utility revenues for our Transmission and Distribution Utilities segment were $(22) million, $(12) million and $(24) million for the years ended December 31, 2013, 2012 and 2011, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $165 million and $187 million as of December 31, 2013 and 2012, respectively.

In March 2012, our Generation & Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation & Marketing segment was $10 million and $34 million for the years ended December 31, 2013 and 2012, respectively. Accrued unbilled revenues for the Generation & Marketing segment were $41 million and $31 million as of December 31, 2013 and 2012, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation (generation plus purchases less sales) 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.

For certain contracts, we calculate unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

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 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of “Property, Plant and Equipment” accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable 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 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost (credit) of the Plans:

Net Periodic Benefit Cost (Credit)	Years Ended December 31, 2013	2012	2011
		(in millions)	
Pension Plans	$ 180	$ 134	$ 118
Postretirement Plans	(17)	89	73

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 2014, 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% for the Qualified Plan and 6.75% 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	
	2014 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2014 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	30 %	8.00 %	66 %	7.80 %
Fixed Income	55 %	4.60 %	33 %	4.40 %
Other Investments	15 %	7.00 %	- %	- %
Cash and Cash Equivalents	- %	- %	1 %	3.00 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6% and 6.75% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 8.1% and 13.8% for the years ended December 31, 2013 and 2012, respectively. The Postretirement Plans' assets had an actual gain of 14.3% and 15.4% for the years ended December 31, 2013 and 2012, 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, 2013, we had cumulative gains of approximately $207 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, 2013 under this method was 4.7% for the Qualified Plan, 4.55% for the Nonqualified Plans and 4.7% 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%, discount rates of 4.7% and 4.55% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $161 million,

$113 million and $109 million in 2014, 2015 and 2016, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 6.75%, a discount rate of 4.7% and various other assumptions, we estimate credits will approximate $77 million, $82 million and $82 million in 2014, 2015 and 2016, 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 was 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 reduced 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 remained unchanged at $4.7 billion as of December 31, 2013 and December 31, 2012 primarily due to investment returns offsetting benefit payments. During 2013, the Qualified Plan paid $324 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.7 billion as of December 31, 2013 from $1.6 billion as of December 31, 2012 primarily due to investment returns and contributions by the company and the participants in excess of benefit payments. The Postretirement Plans paid $140 million in benefits to plan participants during 2013.

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, 2013 Benefit Obligations				
Discount Rate	$ (233)	$ 254	$ (71)	$ 78
Compensation Increase Rate	13	(12)	NA	NA
Cash Balance Crediting Rate	43	(39)	NA	NA
Health Care Cost Trend Rate	NA	NA	25	(28)
Effect on 2013 Periodic Cost				
Discount Rate	(12)	13	(4)	4
Compensation Increase Rate	4	(4)	NA	NA
Cash Balance Crediting Rate	11	(11)	NA	NA
Health Care Cost Trend Rate	NA	NA	4	(4)
Expected Return on Plan Assets	(21)	21	(8)	8

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 Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through its transactions in power, coal, natural gas 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 Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to congestion during the June 2012 – May 2015 Ohio ESP period. Additional risk includes interest rate risk.

Our Generation & 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. In addition, our Generation & Marketing segment is also exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, natural gas and coal trading and marketing contracts.

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, natural gas and, to a lesser extent, heating oil, gasoline 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, Energy Supply, 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 (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee 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 respective committee.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2012:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2013

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation and Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 39	$ (1)	$ 158	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(16)	1	(32)	(47)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-	-	16	16
Changes in Fair Value Due to Market Fluctuations During the Period (b)	-	-	15	15
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	9	3	-	12
Total MTM Risk Management Contract Net Assets as of December 31, 2013	$ 32	$ 3	$ 157	192
Commodity Cash Flow Hedge Contracts				1
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(2)

Fair Value Hedge Contracts	(10)
Collateral Deposits	9
Total MTM Derivative Contract Net Assets as of December 31, 2013	$ 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) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) 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 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2013, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.7%, 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, 2013, 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	$ 630	$ 7	$ 623	2	$ 290
Split Rating	-	-	-	-	-
Noninvestment Grade	-	-	-	-	-
No External Ratings:					
Internal Investment Grade	79	-	79	4	45
Internal Noninvestment Grade	78	11	67	3	46
Total as of December 31, 2013	$ 787	$ 18	$ 769	9	$ 381
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338

In addition, we are exposed to credit risk related to our participation in RTOs. For each of the RTOs in which we participate, this risk is generally determined based on our proportionate share of member gross activity over a specified period of time.

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, 2013, 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 **Twelve Months Ended**

December 31, 2013				December 31, 2012			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 1	$ -	$ -

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

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last several 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, Regulated Risk Committee, or Competitive Risk Committee 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, 2013 and 2012, the estimated EaR on our debt portfolio for the following twelve months was $32 million and $42 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, 2013 and 2012,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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

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, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* 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, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) 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, 2013 of the Company and our report dated February 25, 2014 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

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, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 1992) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2013.

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, 2013, 2012 and 2011
(in millions, except per-share and share amounts)

	Years Ended December 31, 2013	2012	2011
REVENUES			
Vertically Integrated Utilities	$ 9,347	$ 8,785	$ 8,942
Transmission and Distribution Utilities	4,279	4,659	4,982
Generation & Marketing	1,208	882	563
Other Revenues	523	619	629
TOTAL REVENUES	15,357	14,945	15,116
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,068	4,111	4,421
Purchased Electricity for Resale	1,491	1,169	1,191
Other Operation	2,904	2,962	2,868
Maintenance	1,179	1,115	1,236
Asset Impairments and Other Related Charges	226	300	139
Depreciation and Amortization	1,743	1,782	1,655
Taxes Other Than Income Taxes	891	850	824
TOTAL EXPENSES	12,502	12,289	12,334
OPERATING INCOME	2,855	2,656	2,782
Other Income (Expense):			
Interest and Investment Income	58	8	27
Carrying Costs Income	30	53	393
Allowance for Equity Funds Used During Construction	73	93	98
Interest Expense	(906)	(988)	(933)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	2,110	1,822	2,367
Income Tax Expense	684	604	818
Equity Earnings of Unconsolidated Subsidiaries	58	44	27
INCOME BEFORE EXTRAORDINARY ITEM	1,484	1,262	1,576
EXTRAORDINARY ITEM, NET OF TAX	-	-	373
NET INCOME	1,484	1,262	1,949
Net Income Attributable to Noncontrolling Interests	4	3	3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,480	1,259	1,946

Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,480	$ 1,259	$ 1,941
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	486,619,555	484,682,469	482,169,282
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 3.04	$ 2.60	$ 3.25
Extraordinary Item, Net of Tax	-	-	0.77
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.04	$ 2.60	$ 4.02
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	487,040,956	485,084,694	482,460,328
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 3.04	$ 2.60	$ 3.25
Extraordinary Item, Net of Tax	-	-	0.77
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.04	$ 2.60	$ 4.02

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Years Ended December 31,		
	2013	**2012**	**2011**
Net Income	$ 1,484	$ 1,262	$ 1,949
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $8 and $18 in 2013, 2012 and 2011, Respectively	15	(15)	(34)
Securities Available for Sale, Net of Tax of $1, $1 and $1 in 2013, 2012 and 2011, Respectively	3	2	(2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $12, $16 and $13 in 2013, 2012 and 2011, Respectively	22	31	24
Pension and OPEB Funded Status, Net of Tax of $95, $62 and $41 in 2013, 2012 and 2011, Respectively	177	115	(77)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	217	133	(89)
TOTAL COMPREHENSIVE INCOME	1,701	1,395	1,860
Total Comprehensive Income Attributable to Noncontrolling Interests	4	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,697	1,392	1,857
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,697	$ 1,392	$ 1,852

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends ($1.85/share)				(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
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 ($1.88/share)				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
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
Issuance of Common Stock	2	14	70				84
Common Stock Dividends ($1.95/share)				(950)		(4)	(954)
Other Changes in Equity			12			1	13
Net Income				1,480		4	1,484
Other Comprehensive Income					217		217
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY – DECEMBER 31, 2013	508	$ 3,303	$ 6,131	$ 6,766	$ (115)	$ 1	$ 16,086

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2013 and 2012
(in millions)

	December 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 118	$ 279
Other Temporary Investments (December 31, 2013 and 2012 Amounts Include $335 and $311, Respectively, Related to Transition Funding, Phase-in-Recovery Funding, Consumer Rate Relief Funding and EIS)	353	324
Accounts Receivable:		
Customers	746	685
Accrued Unbilled Revenues	157	195
Pledged Accounts Receivable - AEP Credit	945	856
Miscellaneous	72	171
Allowance for Uncollectible Accounts	(60)	(36)
Total Accounts Receivable	1,860	1,871
Fuel	701	844
Materials and Supplies	722	675
Risk Management Assets	160	191
Regulatory Asset for Under-Recovered Fuel Costs	80	88
Margin Deposits	70	76
Prepayments and Other Current Assets	246	241
TOTAL CURRENT ASSETS	4,310	4,589
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,074	26,279
Transmission	10,893	9,846
Distribution	16,377	15,565
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	5,470	3,945
Construction Work in Progress	2,471	1,819
Total Property, Plant and Equipment	60,285	57,454
Accumulated Depreciation and Amortization	19,288	18,691
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	40,997	38,763
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,376	5,106
Securitized Assets	2,373	2,117
Spent Nuclear Fuel and Decommissioning Trusts	1,932	1,706
Goodwill	91	91

Long-term Risk Management Assets	297	368
Deferred Charges and Other Noncurrent Assets	2,038	1,627
TOTAL OTHER NONCURRENT ASSETS	11,107	11,015
TOTAL ASSETS	$ 56,414	$ 54,367

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2013 and 2012
(dollars in millions)

	December 31, 2013	December 31, 2012
CURRENT LIABILITIES		
Accounts Payable	$ 1,266	$ 1,169
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	700	657
Other Short-term Debt	57	324
Total Short-term Debt	757	981
Long-term Debt Due Within One Year (December 31, 2013 and 2012 Amounts Include $416 and $367, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	1,549	2,171
Risk Management Liabilities	90	155
Customer Deposits	299	316
Accrued Taxes	822	747
Accrued Interest	245	269
Regulatory Liability for Over-Recovered Fuel Costs	119	47
Other Current Liabilities	965	968
TOTAL CURRENT LIABILITIES	6,112	6,823
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2013 and 2012 Amounts Include $2,532 and $2,227, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	16,828	15,586
Long-term Risk Management Liabilities	177	214
Deferred Income Taxes	10,300	9,252
Regulatory Liabilities and Deferred Investment Tax Credits	3,694	3,544
Asset Retirement Obligations	1,835	1,696
Employee Benefits and Pension Obligations	415	1,075
Deferred Credits and Other Noncurrent Liabilities	967	940
TOTAL NONCURRENT LIABILITIES	34,216	32,307
TOTAL LIABILITIES	40,328	39,130
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2013	2012

Shares Authorized	600,000,000	600,000,000		
Shares Issued	508,113,964	506,004,962		
(20,336,592 Shares were Held in Treasury as of December 31, 2013 and 2012)			3,303	3,289
Paid-in Capital			6,131	6,049
Retained Earnings			6,766	6,236
Accumulated Other Comprehensive Income (Loss)			(115)	(337)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			16,085	15,237
Noncontrolling Interests			1	-
TOTAL EQUITY			16,086	15,237
TOTAL LIABILITIES AND EQUITY			$ 56,414	$ 54,367

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Years Ended December 31, 2013	2012	2011
OPERATING ACTIVITIES			
Net Income	$ 1,484	$ 1,262	$ 1,949
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,743	1,782	1,655
Deferred Income Taxes	709	636	794
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	226	300	139
Carrying Costs Income	(30)	(53)	(393)
Allowance for Equity Funds Used During Construction	(73)	(93)	(98)
Mark-to-Market of Risk Management Contracts	38	57	37
Amortization of Nuclear Fuel	131	136	137
Pension Contributions to Qualified Plan Trust	-	(200)	(450)
Property Taxes	(35)	(19)	(15)
Fuel Over/Under-Recovery, Net	62	157	(25)
Deferral of Ohio Capacity Costs, Net	(214)	(65)	-
Change in Other Noncurrent Assets	(184)	(171)	(112)
Change in Other Noncurrent Liabilities	3	127	307
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	5	(16)	107
Fuel, Materials and Supplies	122	(224)	176
Accounts Payable	95	(60)	(44)
Accrued Taxes, Net	85	174	193
Other Current Assets	5	(3)	37
Other Current Liabilities	(66)	77	29
Net Cash Flows from Operating Activities	4,106	3,804	3,788
INVESTING ACTIVITIES			
Construction Expenditures	(3,624)	(3,025)	(2,669)
Change in Other Temporary Investments, Net	(11)	(27)	8
Purchases of Investment Securities	(927)	(1,047)	(1,321)
Sales of Investment Securities	858	988	1,379
Acquisitions of Nuclear Fuel	(154)	(107)	(106)
Acquisitions of Assets/Businesses	(32)	(94)	(19)
Acquisition of Cushion Gas from BOA	-	-	(214)
Insurance Proceeds Related to Cook Plant Fire	72	-	-
Proceeds from Sales of Assets	21	18	123
Other Investing Activities	(21)	(97)	(71)
Net Cash Flows Used for Investing Activities	(3,818)	(3,391)	(2,890)

FINANCING ACTIVITIES			
Issuance of Common Stock, Net	84	83	92
Issuance of Long-term Debt	3,207	2,856	1,328
Commercial Paper and Credit Facility Borrowings	17	25	488
Change in Short-term Debt, Net	(221)	(654)	744
Retirement of Long-term Debt	(2,598)	(1,643)	(1,665)
Retirement of Cumulative Preferred Stock	-	-	(64)
Proceeds from Nuclear Fuel Sale/Leaseback	110	-	-
Commercial Paper and Credit Facility Repayments	(20)	(40)	(928)
Principal Payments for Capital Lease Obligations	(82)	(71)	(71)
Dividends Paid on Common Stock	(954)	(916)	(898)
Dividends Paid on Cumulative Preferred Stock	-	-	(2)
Other Financing Activities	8	5	5
Net Cash Flows Used for Financing Activities	(449)	(355)	(971)
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	58	(73)
Cash and Cash Equivalents at Beginning of Period	279	221	294
Cash and Cash Equivalents at End of Period	$ 118	$ 279	$ 221

See Notes to Consolidated Financial Statements beginning on page 60.

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

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

1. <u>ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES</u>

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. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We provide competitive 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.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo will purchase power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo. The transfer of these generation assets and associated liabilities was approved by the FERC, the Virginia SCC and the WVPSC.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Other Impacts of Corporate Separation

In accordance with our December 2010 announcement and our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved:

- PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will 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.

- Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance

Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

- Power Supply Agreement (PSA) between AGR and OPCo for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014.

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 a nonregulated affiliate to bill an affiliated public utility company at 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 currently cost-based within our balancing authority 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 transitioning generation/power supply rates over time to 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 AEP

Transmission Holdco 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 Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the Transmission Coordination Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance

Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a PCA, effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

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.

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 and Securities Available for Sale, including 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 11.

Inventory

Fossil fuel inventories are generally carried at average cost with the exception of AGR and TNC which are carried at the lower of average cost or market. 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, 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. For our nonregulated business, we record allowances at the lower of cost or market. 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 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 Vertically Integrated Utilities 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 original cost retirements, 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

For regulated operations, 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. 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. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

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. The amount of risk taken is determined by the Commercial Operations, Energy Supply 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 (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee 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. 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 FAC under-recovery is no longer probable of recovery, 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 and West Virginia (upon securitization in November 2013) 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 (prior to securitization in November 2013) 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 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 impact 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 in the east service territory is sold to PJM. 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 power, coal and natural gas 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 10.

Barging Activities

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

Levelization of Nuclear Refueling Outage Costs

In 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.

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. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

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	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

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 and prohibit the purchase of 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.

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- 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.

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 debt and equity 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 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Stock-Based Compensation Plans

As of December 31, 2013, we had 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. Upon vesting, performance units are paid in cash and restricted stock units are settled in AEP Common Shares, except for restricted stock units granted after January 1, 2013 and vesting to executive officers, which are paid in cash.

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 become payable to executives in cash 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, 2013, 2012 and 2011 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, 2013, 2012 and 2011, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

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

Amounts Attributable to AEP Common Shareholders	Years Ended December 31, 2013	2012	2011
		(in millions)	
Income Before Extraordinary Item	$ 1,480	$ 1,259	$ 1,568
Extraordinary Item, Net of Tax	-	-	373
Earnings Attributable to AEP Common Shareholders	$ 1,480	$ 1,259	$ 1,941

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, 2013		2012		2011	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,480		$ 1,259		$ 1,941	
Weighted Average Number of Basic Shares Outstanding	486.6	$ 3.04	484.7	$ 2.60	482.2	$ 4.02
Weighted Average Dilutive Effect of:						
Stock Options	-	-	-	-	0.1	-
Restricted Stock Units	0.4	-	0.4	-	0.2	-
Weighted Average Number of Diluted Shares Outstanding	487.0	$ 3.04	485.1	$ 2.60	482.5	$ 4.02

There were no antidilutive shares outstanding as of December 31, 2013, 2012 and 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generation 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, we impaired certain Ohio generating units (see Note 7). As a result of this impairment of the full book value of these assets, we ceased depreciation on these generating units effective December 1, 2012.

In the second quarter of 2013, we impaired Muskingum River Plant, Unit 5 (MR5). As a result of this impairment of the full book value of this generating unit, we ceased depreciation on MR5 effective July 1, 2013.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2013, 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 generation plants. These environmental projects were funded through debt issuances. As of December 31, 2013, both generation plants were operating with new environmental controls.

The following details related party transactions for the years ended December 31, 2013, 2012 and 2011:

Related Party Transactions	Years Ended December 31, 2013	2012	2011
		(in millions)	
AEP Consolidated Revenues – Other Revenues			
OVEC – Barging and Other Transportation Services	$ 21	$ 30	$ 37
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	289	273	383 (a)

(a) The parties to the Interconnection Agreement purchased power from OVEC to serve retail sales in 2011. The total amount reported in 2011 includes $66 million related to this agreement.

Supplementary Cash Flow Information

Cash Flow Information	Years Ended December 31, 2013	2012	2011
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 882	$ 931	$ 900
Income Taxes	(55)	(82)	(118)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	182	63	54
Construction Expenditures Included in Current Liabilities as of December 31,	492	439	380
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	4	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. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following table are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges			Pension and OPEB		
	Commodity	**Interest Rate and Foreign Currency**	**Securities Available for Sale**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)			
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ 4	$ 112	$ (415)	$ (337)
Change in Fair Value Recognized in AOCI	10	2	3	-	177	192
Amounts Reclassified from AOCI	(2)	5	-	22	-	25
Net Current Period Other Comprehensive Income	8	7	3	22	177	217
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	-	5	5
Balance in AOCI as of December 31, 2013	$ -	$ (23)	$ 7	$ 134	$ (233)	$ (115)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	**Amount of (Gain) Loss Reclassified from AOCI (in millions)**
Commodity:	
Vertically Integrated Utilities Revenues	$ (1)
Generation & Marketing Revenues	(10)
Purchased Electricity for Resale	8
Property, Plant and Equipment	-
Regulatory Assets/(Liabilities), Net (a)	-
Subtotal - Commodity	(3)
Interest Rate and Foreign Currency:	
Interest Expense	7
Subtotal - Interest Rate and Foreign Currency	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	4
Income Tax (Expense) Credit	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	3
Gains and Losses on Securities Available for Sale	
Interest Income	-
Interest Expense	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	-
Income Tax (Expense) Credit	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	-
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(21)
Amortization of Actuarial (Gains)/Losses	55
Reclassifications from AOCI, before Income Tax (Expense) Credit	34
Income Tax (Expense) Credit	12
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	22
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 25

Represents realized gains and losses subject to regulatory accounting treatment recorded as either

(a) current or noncurrent on the balance sheets.

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 and 2011. 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:			
Vertically Integrated Utilities Revenues	-	-	-
Generation & Marketing 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
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:			
Vertically Integrated Utilities Revenues	1	-	1
Generation & Marketing Revenues	(3)	-	(3)
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
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

Represents realized gains and losses subject to regulatory accounting treatment recorded as either

(a) current or noncurrent on the balance sheets.

The following table provides details of changes in unrealized gains and losses related to Securities Available for Sale and the reasons for changes for the year ended December 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Securities Available for Sale
Year Ended December 31, 2012

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

4. RATE MATTERS

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

OPCo Rate Matters

Ohio Electric Security Plan Filings

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 (OCC) 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, 2013, OPCo's net deferred fuel balance was $445 million, excluding unrecognized equity carrying costs. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU. In February 2014, the IEU filed for reconsideration of the Supreme Court of Ohio decision.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover deferred fuel costs in 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. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 – 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues which could reduce OPCo's net deferred fuel balance up to the total balance. These intervenors' appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of December 31, 2013, could reduce carrying costs by $31 million including $16 million of 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. The 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 project. In September 2013, a proposed second phase of OPCo's *gridSMART*® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO. In October 2013, the PUCO issued an order on the 2010 SEET filing that determined there were excessive earnings of $7 million, which were primarily offset against deferred fuel, as ordered. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. In November 2013, OPCo filed its 2011 and 2012 SEET filings with the PUCO. In February 2014, the PUCO staff filed testimony asserting that no significantly excessive earnings had occurred in 2011 for CSPCo or OPCo and that no significantly excessive earnings had occurred in 2012 for OPCo. In February 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. A hearing at the PUCO related to the 2011 SEET filing is scheduled for February 2014. Management does not believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in either 2012 or 2013 for OPCo.

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

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. This ruling was generally upheld in rehearing orders in January and March 2013.

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 $33/MW day through May 2014 and $148/MW day from June 2014 through May 2015. 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 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is being collected from customers at $3.50/MWh through May 2014 and will be collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. As of December 31, 2013, OPCo's incurred deferred capacity costs balance of $288 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

In January and March 2013, the PUCO issued its Orders 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 expenses 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 related to the competitive bid process (CBP). In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. OPCo must conduct an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 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. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In December 2013, the PUCO granted applications for rehearing for further consideration filed by OPCo and intervenors. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012-2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC.

If OPCo is ultimately not permitted to fully collect its ESP rates including the RSR, and its fixed fuel and deferred capacity costs, it could reduce future net income and cash flows and impact financial condition.

Proposed June 2015 – May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the first quarter of 2014.

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 and associated generation liabilities at net book value to AGR. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, the PUCO approved OPCo's application to amend the corporate separation plan by permitting OPCo to retain certain rights to purchase power from OVEC. The approval is subject to the condition that energy from the OVEC entitlements are sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. In December 2013, corporate separation of OPCo's generation assets was completed. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters.

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. In December 2013, a stipulation agreement was reached between OPCo, the PUCO staff and all intervenors except the OCC. The stipulation included a $6 million reduction in the amount of 2012 storm expenses to be recovered and for recovery of those expenses to take place over a 12-month period. The agreement also states that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. In December 2013, the OCC filed testimony opposing the stipulation. The testimony recommended the disallowance of approximately $18 million of the 2012 storm expenses and that the remaining 2012 storm expenses be offset by an additional $20 million that OPCo was ordered to spend on a solar project in OPCo's 2009 SEET filing. See the "2009-2011 ESP" section above. Hearings were held at the PUCO in January 2014 related to the settlement agreement and to address issues presented in the OCC's testimony. As of December

31, 2013, OPCo has deferred $56 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 could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC 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. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 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 regarding valuation of the coal reserve. 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 an appeal 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 with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. Hearings at the PUCO were held in November 2013. If the PUCO orders result in a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition. See the 2009-2011 ESP section of the "Ohio Electric Security Plan Filing" related to the PUCO order in the PIRR proceeding.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down operations effective immediately. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider, except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet's October and November 2012 power bills. OPCo expects that any additional unpaid generation usage by Ormet will be recoverable as a regulatory asset through the Economic Development Rider (EDR). In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommends approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR which, as of December 31, 2013, is recorded in regulatory assets on the balance sheet. Also in February 2014, intervenor comments were filed objecting to full recovery of these forgone revenues.

In addition, in the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. 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. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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, 2013, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest.

Management cannot predict the outcome of this proceeding concerning the Ohio IGCC plant or what effect, if any, this proceeding could 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 facility. As of December 31, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.758 billion. As of December 31, 2013, a pretax provision of $59 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total net capitalized expenditures of $1.699 billion.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). 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 an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This Turk Plant output that is currently not subject to cost-based rate recovery and is being sold into the wholesale 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 cash construction cost, excluding 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. The PUCT decision was upheld on appeal. See the "2012 Texas Base Rate Case" disclosure below for a discussion of a PUCT order on the Texas capital cost cap.

If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant or transmission lines, it could 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 and (b) included a return on and of the Stall Unit as of December 2011 and associated operation and maintenance costs.

In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determining that the Turk Plant Texas capital cost cap established in the Certificate of Convenience and Necessity (CCN) case discussed above (the Texas capital cost cap) also limited SWEPCo's recovery of AFUDC in addition to its recovery of cash construction costs. As a result of the determination that AFUDC was to be included in the cap, in the third quarter of 2013, SWEPCo recorded an additional pretax regulatory disallowance of $111 million. The order approved an annual rate increase of approximately $39 million based upon a return on common equity of 9.65%, including an unfavorable consolidated income tax adjustment of $5 million. As a result of this approval, SWEPCo retroactively applied the rate increase to the end of January 2013. The order also provided that there would be no disallowance to the existing book investment in the Stall Unit and that the Turk Plant related transmission line investment that was not in service at the end of the test year would be excluded from rate base. SWEPCo has since sought approval to recover this transmission investment through a Transmission Cost Recovery Rider in a filing made in December 2013. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of December 31, 2013, the net book value of Welsh Plant, Unit 2 was $87 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, SWEPCo filed a motion for rehearing with the PUCT. In December 2013, the PUCT issued an order granting rehearing and reversed its decision on consolidated tax savings increasing SWEPCo's annual revenues by $5 million. In January 2014, the PUCT determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result of these rulings, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. These rulings also increased SWEPCo's previously approved annual base rates by a total of $13 million, which was also retroactively applied to the end of January 2013. The resulting annual base rate increase is approximately $52 million.

If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Welsh Plant, Unit 2 and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

2013 Texas Transmission Costs Recovery Factor Filing

In December 2013, SWEPCo filed an application to implement its initial transmission cost recovery factor (TCRF) requesting additional annual revenue of $10 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In January and February 2014, intervenors filed motions with the PUCT opposing SWEPCo's filing. In February 2014, an Administrative Law Judge issued an order requesting additional information from SWEPCo related to this filing. If the PUCT were to disallow any portion of the TCRF, it could reduce future net income and cash flows.

2012 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 approved by the LPSC. The settlement increased Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The 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 the prudency review of the Turk Plant. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In May 2013, SWEPCo filed testimony in the prudence review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudency review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

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. In July 2013, the APSC approved the request to install environmental controls at the Flint Creek Plant.

APCo and WPCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC regarding the transfer of certain generation plants within the AEP System. 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 generating capacity. In July 2013, the Virginia SCC approved the transfer of the two-thirds interest in the Amos Plant, Unit 3 to APCo, but directed that an amount equal to $83 million pretax be removed from the proposed transfer price. The Virginia jurisdictional share of the disallowance was approximately $39 million. The Virginia SCC also denied the proposed transfer of the one-half interest in the Mitchell Plant to APCo.

In December 2013, the WVPSC approved the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the recovery of West Virginia's jurisdictional share of the $83 million pretax Virginia SCC disallowance until APCo's next West Virginia base rate case which APCo has agreed to file no later than June 2014. The West Virginia and FERC jurisdictional share of the potential disallowance is approximately $44 million pretax. Additionally, the WVPSC order also approved a rate surcharge for Amos Plant, Unit 3 effective January 2014 and deferred ruling on the transfer of the one-half interest in the Mitchell Plant to APCo. The surcharge was offset by an equal reduction in ENEC revenue with no overall change in total revenue.

In December 2013, the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo was completed. As a result of the Virginia order, in the fourth quarter of 2013, APCo recorded a pretax regulatory disallowance of $39 million in Asset Impairments and Other Related Charges on the statement of income. Management continues to review its options related to the remaining one-half interest in the Mitchell Plant currently owned by AGR. If APCo and WPCo are not ultimately permitted to recover their Amos Plant, Unit 3 incurred costs in West Virginia and FERC, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of December 31, 2013, 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 $10 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Environmental Rate Adjustment Clause (Environmental RAC) Filing

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover $39 million related to 2012 and 2011 environmental compliance costs, including carrying costs. In March 2013, the environmental RAC surcharge expired related to the collection of 2009 and 2010 environmental compliance costs. In November 2013, the Virginia SCC approved a settlement agreement which recommended approval of an environmental RAC to recover $38 million of the 2012 and 2011 environmental compliance costs, effective January 2014 for a one-year period. The order also states that APCo must file its next environmental RAC petition on or before May 1, 2015. As of December 31, 2013, APCo has deferred $28 million for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding $10 million of unrecognized equity carrying costs.

2013 Virginia Generation Rate Adjustment Clause (Generation RAC)Filing

In March 2013, APCo filed with the Virginia SCC to increase its generation RAC revenues by $12 million for a total of $38 million to collect costs related to the Dresden Plant. In December 2013, the Virginia SCC approved a settlement agreement that included an increase in the generation RAC to $39 million. Per the approved settlement agreement, the generation RAC increase was effective in February 2014 for a period of one year at which time the component to collect an under-recovery of approximately $10 million will cease and the remaining annual $29 million revenue to recover on-going Dresden Plant costs will continue. As of December 31, 2013, APCo has deferred $6 million for the Virginia portion of unrecovered costs of the Dresden Plant, excluding $5 million of unrecognized equity carrying costs.

2013 Virginia Transmission Rate Adjustment Clause (Transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually. The increase in the transmission RAC is expected to be effective May 2014. In February 2014, a hearing was held at the Virginia SCC in which a stipulation agreement between APCo and the Virginia SCC staff was submitted to the Virginia SCC that recommended approval to increase the transmission RAC revenues by $49 million annually, subject to true-up. The stipulation included the Virginia SCC staff's commitment to fully audit APCo's transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo's next transmission RAC filing in 2015. As of December 31, 2013, APCo has deferred $47 million for the Virginia portion of unrecovered transmission RAC costs. If the Virginia SCC were to disallow any portion of the transmission RAC, it could reduce future net income and cash flows.

2013 West Virginia Expanded Net Energy Charge (ENEC) Filing

In March 2012, West Virginia passed securitization legislation which allowed the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred ENEC balances and other ENEC-related assets. In August 2013, the WVPSC approved a settlement that included (a) a $56 million reduction in ENEC revenues, offset by a $6 million annual increase in construction surcharges, effective September 2013 and subject to true-up, (b) an agreement to file a base case no later than June 2014 and (c) the deferral of $21 million from the ENEC recovery balance with the ability to include that amount in the ENEC recovery balance upon reaching certain coal inventory levels at the Amos Plant. In September 2013, the WVPSC approved a settlement agreement filed by APCo, WPCo and intervenors which authorized APCo to securitize $376 million, plus upfront financing costs, primarily related to the December 2011 under-recovered ENEC deferral balance. In November 2013, APCo issued $380 million of Securitization Bonds to securitize the under-recovered ENEC deferral balance, including $4 million of upfront financing costs, with a final maturity date of August 2031. APCo implemented a new securitization rider which was offset by an equal reduction in ENEC revenues, with no overall change in total revenues.

As of December 31, 2013, APCo's ENEC net over-recovery balance was $86 million, of which $107 million was recorded in Regulatory Liabilities and $21 million was recorded in Regulatory Assets on the balance sheet.

Virginia Storm Costs

In March 2013, due to the 2013 enactment of a Virginia law, APCo wrote off $30 million of previously deferred 2012 Virginia storm costs. The change in law affected the test years to be included in APCo's next biennial Virginia base rate filing in March 2014 and the determination of how these costs are treated in the Virginia jurisdictional biennial earnings test for 2012 and 2013. As of December 31, 2013, APCo has not deferred any Virginia storm costs incurred in 2012 or 2013 based on actual 2012 and estimated 2013 Virginia jurisdictional earnings. The 2012 and 2013 earnings test will be filed in the first quarter of 2014 as part of APCo's biennial Virginia base rate filing.

PSO Rate Matters

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional types of transmission costs that are expected to increase over the next several years.

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. As of December 31, 2013, the net book values of NES, Units 3 and 4 were $208 million and $106 million, respectively, before cost of removal, including materials and supplies inventory and CWIP. In August 2013, the OCC dismissed PSO's environmental compliance plan case without prejudice but will permit PSO to seek recovery in a future proceeding. PSO will address the environmental compliance plan issues in future regulatory proceedings when it seeks cost recovery of the plan. If PSO is ultimately not permitted to fully recover its net book value of NES, Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

<u>I&M Rate Matters</u>

2011 Indiana Base Rate Case

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%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from $85 million to $92 million. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed a request for reconsideration with the IURC, which was denied. Also in March 2013, the OUCC filed an appeal of the order with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to the inclusion of a prepaid pension asset in rate base, the use of an end-of-test-year amount for materials and supplies instead of a thirteen-month average and the application of an "outdated" capital structure. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the 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 (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In November 2013, the OUCC filed testimony identifying concerns related to the LCM rider that included the use of forecasted capital expenditures and the method used to calculate carrying charges. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project.

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

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost in the application was $285 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. I&M also requested cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism.

In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share. The settlement agreement specifies that 80% of the recoverable I&M direct ownership share of CCT Project costs will be recovered through a Federal Mandate Rider with the remaining 20% deferred until rates are established in a subsequent rate case. I&M's Indiana jurisdictional allocated share of the CCT Project costs received in the form of purchased power from AEGCo will be recovered in subsequent I&M rate cases. As of December 31, 2013, we have incurred costs of $109 million related to the CCT Project, including AFUDC.

Tanners Creek Plant, Units 1 - 4

In 2011, I&M announced that it would retire Tanners Creek Plant, Units 1-3 by June 2015 to comply with proposed environmental regulations. In September 2013, I&M announced that Tanners Creek Plant, Unit 4 would also be retired in mid-2015 rather than being converted from coal to natural gas. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant's retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposes that the net book value of the Tanners Creek Plant will be recovered over the remaining life of the Rockport Plant. I&M requested to have the impact of these new depreciation rates incorporated into the rates set in its next rate case. The new depreciation rates result in a decrease in I&M's Michigan jurisdictional electric depreciation expense which I&M proposes to implement in the month following a MPSC order in the revised depreciation case.

As of December 31, 2013, the net book value of the Tanners Creek Plant was $341 million, before cost of removal, including materials and supplies inventory and CWIP. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

<u>KPCo Rate Matters</u>

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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

FERC Rate Matters

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 (NBV) approximately 9,200 MW of OPCo-owned generation assets and associated liabilities to AGR. The AEP East Companies also requested FERC approval to transfer at NBV two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer the Mitchell Plant at NBV to APCo and KPCo in equal one-half interests (780 MW each) to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, the transfers of the Amos Plant and Mitchell Plant to APCo and KPCo, respectively, and the merger of APCo and WPCo. In January 2014, the FERC dismissed an IEU petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. Similar asset transfer filings were made at the KPSC, the Virginia SCC and the WVPSC. In December 2013, corporate separation of OPCo's generation assets was completed. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

In accordance with our December 2010 announcement and our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

In December 2013, the FERC issued orders approving the creation of the PCA, effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' 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.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

Additionally, FERC approval was sought for a Power Supply Agreement (PSA) between AGR and OPCo. This agreement provides for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through an auction from January 1, 2014 through December 31, 2014. In December 2013, the FERC issued an order approving the PSA. The order conditioned the acceptance of the PSA on the revision of the agreement to reflect the PUCO's current and future underlying rates and rate structure. In January 2014, initial revisions to reflect current underlying rates and rate structure were filed at the FERC.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters for a discussion of those orders.

If incurred costs are not ultimately recovered, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulated Generating Units to be Retired Before or During 2016

The following regulated generating units are probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2013. The following table summarizes the plant investment and cost of removal, currently being recovered, for each generating unit as of December 31, 2013.

Plant Name and Unit	Company	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(in millions)				
Tanners Creek Plant, Units 1-4	I&M	$ 681	$ 354	$ 327	$ 87	2015	17 years
Big Sandy Plant, Unit 2	KPCo	424	180	244	47	2015	27 years
Northeastern Station, Unit 4	PSO	182	89	93	11	2016	27 years
Welsh Plant, Unit 2	SWEPCo	175	93	82	19	2016	27 years
Total		$ 1,462	$ 716	$ 746	$ 164		

In accordance with accounting guidance for "Regulated Operations", APCo regulated generating units expected to be retired before or during 2016 are not considered probable of abandonment.

Regulatory Assets

Regulatory assets are comprised of the following items:

	December 31, 2013	December 31, 2012	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 61	$ 86	1 year
Under-recovered Fuel Costs - does not earn a return	19	2	1 year
Total Current Regulatory Assets	$ 80	$ 88	
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	$ 22	$ 23	
Ohio Economic Development Rider	14	13	
Other Regulatory Assets Not Yet Being Recovered	4	1	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	161	172	
Ormet Special Rate Recovery Mechanism	36	5	
Indiana Under-Recovered Capacity Costs	22	-	
Expanded Net Energy Charge - Coal Inventory	21	-	
Mountaineer Carbon Capture and Storage Product Validation Facility	13	14	
Virginia Environmental Rate Adjustment Clause	2	29	
Litigation Settlement	-	11	
Other Regulatory Assets Not Yet Being Recovered	35	36	
Total Regulatory Assets Not Yet Being Recovered	330	304	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	445	519	5 years
Ohio Capacity Deferral	288	66	5 years
Ohio Transmission Cost Recovery Rider	87	49	2 years
Unamortized Loss on Reacquired Debt	81	82	30 years
Texas Meter Replacement Costs	77	47	15 years
Ohio Distribution Decoupling	31	-	2 years
Storm Related Costs	17	36	5 years
RTO Formation/Integration Costs	12	15	6 years
Red Rock Generating Facility	10	10	43 years
West Virginia Expanded Net Energy Charge	-	273	
Ohio Deferred Asset Recovery Rider	-	152	
Other Regulatory Assets Being Recovered	18	15	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	1,390	1,353	55 years

Pension and OPEB Funded Status	1,157	1,896	11 years
Cook Nuclear Plant Refueling Outage Levelization	58	27	3 years
Medicare Subsidy	51	-	11 years
Virginia Transmission Rate Adjustment Clause	47	33	2 years
Peak Demand Reduction/Energy Efficiency	44	12	2 years
Postemployment Benefits	40	45	5 years
United Mine Workers of America Pension Withdrawal	27	-	12 years
Virginia Environmental Rate Adjustment Clause	27	8	1 year
Under-Recovery of Transmission Cost Recovery Factor	20	6	1 year
Storm Related Costs	18	27	5 years
Vegetation Management	14	13	1 year
Deferred Restructuring Costs	11	15	5 years
Litigation Settlement	10	-	12 years
Under-Recovered Distribution Investment Rider	9	1	1 year
Asset Retirement Obligation	8	9	33 years
West Virginia Expanded Net Energy Charge	-	26	
Ohio Distribution Decoupling	-	16	
Deferred PJM Fees	-	14	
Unrealized Loss on Forward Commitments	-	8	
Other Regulatory Assets Being Recovered	49	29	various
Total Regulatory Assets Being Recovered	4,046	4,802	
Total Noncurrent Regulatory Assets	$ 4,376	$ 5,106	

Regulatory Liabilities

Regulatory liabilities are comprised of the following items:

	December 31, 2013	2012	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 9	$ 25	1 year
Over-recovered Fuel Costs - does not pay a return	110	22	1 year
Total Current Regulatory Liabilities	$ 119	$ 47	
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	
Other Regulatory Liabilities Not Yet Being Paid	5	4	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	3	9	
Total Regulatory Liabilities Not Yet Being Paid	8	109	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,589	2,511	(a)
Louisiana Refundable Construction Financing Costs	78	-	5 years
Advanced Metering Infrastructure Surcharge	68	83	7 years
Deferred Investment Tax Credits	29	23	47 years
Excess Earnings	12	12	40 years
Other Regulatory Liabilities Being Paid	1	1	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	597	436	(b)
Deferred Investment Tax Credits	121	136	49 years
Spent Nuclear Fuel Liability	43	43	(b)
Over-Recovery of Transition Charges	40	57	14 years
Unrealized Gain on Forward Commitments	35	46	4 years
Deferred State Income Tax Coal Credits	28	29	10 years
Peak Demand Reduction/Energy Efficiency	18	31	1 year
Over-Recovery of PJM Expense	14	-	2 years
Other Regulatory Liabilities Being Paid	13	27	various
Total Regulatory Liabilities Being Paid	3,686	3,435	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,694	$ 3,544	

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

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material 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. 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, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,387	$ 3,358	$ 2,189	$ 2,480	$ 10,414
Energy and Capacity Purchase Contracts	195	410	457	2,634	3,696
Construction Contracts for Capital Assets (b)	146	-	-	-	146
Total	$ 2,728	$ 3,768	$ 2,646	$ 5,114	$ 14,256

(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 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 natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters of credit. As of December 31, 2013, the maximum future payments for letters of credit issued under the revolving credit facilities were $170 million with maturities ranging from February 2014 to April 2015.

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility signed in October 2013. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $352 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $356 million. The letters of credit have maturities ranging from March 2014 to March 2015. In February 2014, $106 million of bilateral letters of credit maturing in March 2014 were extended to March 2017.

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. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of December 31, 2013, SWEPCo has collected approximately $62 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $46 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. As of December 31, 2013, 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 13 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. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court’s dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme

Court.

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. 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 filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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 generation 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, 2013, 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 $8 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 $10 million, $14 million and $14 million for the years ended December 31, 2013, 2012 and 2011, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2013 and 2012, the total decommissioning trust fund balance was $1.6 billion and $1.4 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, 2013 and 2012, 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 $309 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 $31 million, $20 million and $14 million in 2013, 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, 2016. The proceeds reduced costs for dry cask storage. As of December 31, 2013, I&M has deferred $22 million in Prepayments and Other Current Assets and $7 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 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for a nuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of $2.8 billion. Insurance coverage for a nonnuclear incident at the Cook Plant is $1.7 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $39 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 $13.6 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 $121 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $242 million per nuclear incident payable in annual installments of $38 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 $13.2 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.

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.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The appellate court reversed the district court's holding that the state antitrust claims were preempted by the Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. AEP filed a motion with the appellate court for rehearing on the issue of whether the district court had personal jurisdiction of AEP in the two referenced cases. No decision has been rendered on that motion. Defendants in these cases, including AEP, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue, which is pending. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine a range of potential losses that are reasonably possible of occurring.

7. ACQUISITIONS AND IMPAIRMENTS

ACQUISITIONS

2012

BlueStar Energy (Generation & 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.

Other Matters

Enron Bankruptcy (Corporate and Other)

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.

IMPAIRMENTS

2013

Amos Plant, Unit 3 (Vertically Integrated Utilities segment)

In July 2013, the Virginia SCC approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but, for rate purposes, reduced the proposed transfer price by $83 million pretax. The Virginia jurisdictional share of the reduced price is approximately $39 million. In December 2013, the WVPSC issued an order that approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the $83 million pretax reduction in transfer price until APCo's next base rate case. The West Virginia and FERC jurisdictional share of the potential reduced transfer price is approximately $44 million. Upon evaluation, management believes the West Virginia jurisdictional share is probable of recovery. As a result of the Virginia order, in the fourth quarter of 2013, we recorded a pretax impairment of $39 million in Asset Impairments and Other Related Charges on the statement of income. See the "Plant Transfer" section of Note 4.

Big Sandy Plant, Unit 2 FGD Project (Vertically Integrated Utilities segment)

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Note 4.

Muskingum River Plant, Unit 5 (Generation & Marketing segment)

In May 2013, the U.S. District Court for the Southern District of Ohio approved a modification to the consent decree, which was initially entered into in 2007, requiring certain types of pollution control equipment to be installed at certain AEP plants, including the 600 MW Muskingum River Plant, Unit 5 (MR5) coal-fired generation plant. Under the modification to the consent decree, we have the option to cease burning coal and retire MR5 in 2015 or to cease burning coal in 2015 and complete a natural gas refueling project no later than June 2017. In the second quarter of 2013, based on the approval of the modified consent decree and changes in other market factors, we re-evaluated potential courses of action with respect to the planned operation of MR5 and concluded that completion of a refueling project, which would have extended the useful life of MR5, is remote. As a result, management completed an impairment analysis and concluded that MR5 was impaired. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of this generating unit was zero based on the lack of installed environmental control equipment and the nature and condition of this generating unit. In the second quarter of 2013, we recorded a pretax impairment of $154 million in Asset Impairments and Other Related Charges on the statement of income which includes a $6 million pretax impairment of related material and supplies inventory. Management expects to retire the plant in 2015.

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 (Generation & Marketing 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 we had a material impairment of certain Ohio 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, we 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 (Vertically Integrated Utilities 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 (Vertically Integrated Utilities 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) (Generation & Marketing segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, we determined that we were 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, we recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant, Unit 5 (Generation & Marketing segment)

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

8. BENEFIT PLANS

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

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide 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	**2013**	**2012**	**2013**	**2012**
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
Rate of Compensation Increase	4.85 % (a)	4.95 % (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 2013, 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 4.85%.

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		
	2013	2012	2011	2013	2012	2011
Discount Rate	3.95 %	4.55 %	5.05 %	3.95 %	4.75 %	5.25 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.75 %	7.00 %	7.25 %	7.50 %
Rate of Compensation Increase	4.95 %	4.85 %	4.85 %	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	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

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	$ 6	$ (4)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	74	(59)

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, 2013, 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, 2013 and 2012

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	
	2013	2012	2013	2012
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 5,205	$ 4,991	$ 1,849	$ 2,227
Service Cost	69	76	23	47
Interest Cost	203	223	71	103
Actuarial (Gain) Loss	(305)	299	(395)	148
Plan Amendment Prior Service Credit	-	-	-	(570)
Curtailment and Settlements	-	(1)	-	-
Benefit Payments	(331)	(383)	(140)	(151)
Participant Contributions	-	-	39	35
Medicare Subsidy	-	-	9	10
Benefit Obligation as of December 31,	$ 4,841	$ 5,205	$ 1,456	$ 1,849
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,696	$ 4,303	$ 1,568	$ 1,410
Actual Gain on Plan Assets	340	560	208	178
Company Contributions	6	216	24	96
Participant Contributions	-	-	39	35
Benefit Payments	(331)	(383)	(140)	(151)
Fair Value of Plan Assets as of December 31,	$ 4,711	$ 4,696	$ 1,699	$ 1,568
Funded (Underfunded) Status as of December 31,	$ (130)	$ (509)	$ 243	$ (281)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
	(in millions)			
Deferred Charges and Other Noncurrent Assets - Prepaid Benefit Costs	$ -	$ -	$ 264	$ -
Other Current Liabilities - Accrued Short-term Benefit Liability	(7)	(7)	(4)	(4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(123)	(502)	(17)	(277)
Funded (Underfunded) Status	$ (130)	$ (509)	$ 243	$ (281)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

Components	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
	(in millions)			
Net Actuarial Loss	$ 1,561	$ 2,111	$ 428	$ 989
Prior Service Cost (Credit)	8	11	(693)	(762)
Recorded as				
Regulatory Assets	$ 1,343	$ 1,774	$ (191)	$ 108
Deferred Income Taxes	79	122	(26)	42
Net of Tax AOCI	147	226	(48)	77

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2013 and 2012 are as follows:

Components	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
	(in millions)			
Actuarial (Gain) Loss During the Year	$ (367)	$ 58	$ (496)	$ 67
Prior Service Credit	-	-	-	(570)
Amortization of Actuarial Loss	(183)	(155)	(65)	(57)
Amortization of Prior Service Credit (Cost)	(3)	1	69	18
Amortization of Transition Obligation	-	-	-	(1)
Change for the Year	$ (553)	$ (96)	$ (492)	$ (543)

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, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,092	$ -	$ -	$ -	$ 1,092	23.2 %
International	514	-	-	-	514	10.9 %
Real Estate Investment Trusts	58	-	-	-	58	1.2 %
Common Collective Trust - International	-	10	-	-	10	0.2 %
Subtotal - Equities	1,664	10	-	-	1,674	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.5 %
United States Government and Agency Securities	-	387	-	-	387	8.2 %
Corporate Debt	-	1,600	-	-	1,600	34.0 %
Foreign Debt	-	344	-	-	344	7.3 %
State and Local Government	-	28	-	-	28	0.6 %
Other - Asset Backed	-	33	-	-	33	0.7 %
Subtotal - Fixed Income	-	2,418	-	-	2,418	51.3 %
Real Estate	-	-	238	-	238	5.0 %
Alternative Investments	-	-	330	-	330	7.0 %
Securities Lending	-	35	-	-	35	0.8 %
Securities Lending Collateral (a)	-	-	-	(45)	(45)	(0.9)%
Cash and Cash Equivalents	-	48	-	-	48	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	13	13	0.3 %
Total	$ 1,664	$ 2,511	$ 568	$ (32)	$ 4,711	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:

	Real Estate	Alternative Investments	Total Level 3

Balance as of January 1, 2013	$ 220	$ 195	$ 415
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	26	15	41
Relating to Assets Sold During the Period	-	15	15
Purchases and Sales	(8)	105	97
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 238	$ 330	$ 568

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 473	$ -	$ -	$ -	$ 473	27.9 %
International	616	-	-	-	616	36.2 %
Common Collective Trust - Global	-	15	-	-	15	0.9 %
Subtotal - Equities	1,089	15	-	-	1,104	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	88	-	-	88	5.2 %
United States Government and Agency Securities	-	56	-	-	56	3.3 %
Corporate Debt	-	110	-	-	110	6.5 %
Foreign Debt	-	22	-	-	22	1.2 %
State and Local Government	-	5	-	-	5	0.3 %
Other - Asset Backed	-	8	-	-	8	0.5 %
Subtotal - Fixed Income	-	289	-	-	289	17.0 %
Trust Owned Life Insurance:						
International Equities	-	13	-	-	13	0.8 %
United States Bonds	-	211	-	-	211	12.4 %
Cash and Cash Equivalents	68	9	-	-	77	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	5	5	0.3 %
Total	$ 1,157	$ 537	$ -	$ 5	$ 1,699	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, 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.

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.

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	December 31, 2013	2012
	(in millions)	
Qualified Pension Plan	$ 4,638	$ 5,001
Nonqualified Pension Plans	77	82

Total	$ 4,715	$ 5,083

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, 2013 and 2012 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2013	2012
	(in millions)	
Projected Benefit Obligation	$ 4,841	$ 5,205
Accumulated Benefit Obligation	$ 4,715	$ 5,083
Fair Value of Plan Assets	4,711	4,696
Underfunded Accumulated Benefit Obligation	$ (4)	$ (387)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $80 million and the OPEB plans of $6 million during 2014. 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 was capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. 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)	
2014	$ 355	$ 140	$ -
2015	363	145	-
2016	368	149	-
2017	372	152	-
2018	377	156	-
Years 2019 to 2023, in Total	1,857	809	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for the years ended December 31, 2013, 2012 and 2011:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	(in millions)					
Service Cost	$ 69	$ 76	$ 72	$ 23	$ 47	$ 42
Interest Cost	203	223	237	71	103	109
Expected Return on Plan Assets	(278)	(319)	(314)	(107)	(101)	(109)
Curtailment	-	-	-	-	-	1
Amortization of Transition Obligation	-	-	-	-	1	2
Amortization of Prior Service Cost (Credit)	3	(1)	1	(69)	(18)	(1)
Amortization of Net Actuarial Loss	183	155	122	65	57	29
Net Periodic Benefit Cost (Credit)	180	134	118	(17)	89	73
Capitalized Portion	(56)	(42)	(37)	5	(28)	(22)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 124	$ 92	$ 81	$ (12)	$ 61	$ 51

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 125	$ 21
Prior Service Cost (Credit)	2	(69)
Total Estimated 2014 Amortization	$ 127	$ (48)
Expected to be Recorded as		
Regulatory Asset	$ 107	$ (34)
Deferred Income Taxes	7	(5)
Net of Tax AOCI	13	(9)
Total	$ 127	$ (48)

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 $67 million in 2013, $66 million in 2012 and $64 million in 2011.

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, 2013 and 2012, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA.

Contributions to the UMWA pension plan in 2013, 2012 and 2011 were made under a collective bargaining agreement that is scheduled to expire December 31, 2017. We contributed immaterial amounts in 2013, 2012 and 2011 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2013, 2012 and 2011. The contributions we made did not include a surcharge. There are no minimum contributions for future years.

Based upon the plan to retrofit the Rockport Plant with dry sorbent injection technology to meet environmental emission control requirements, the timing of the closure of Cook Coal Terminal is expected to be in or after 2025. Due to the estimated closure date and the ability to estimate the amount of the withdrawal liability, we recorded a liability of $39 million during 2013 and a related regulatory asset of $30 million. The regulatory asset should be recovered in future billings for transloading services before the planned closure.

9. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Vertically Integrated Utilities 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.

During the fourth quarter of 2013, we changed the structure of our internal organization which resulted in a change in the composition of our reportable segments. In accordance with authoritative accounting guidance for segment reporting, prior period financial information has been recast in the financial statements and footnotes to be comparable to the current year presentation of reportable segments. See the "Corporate Separation" section of Executive Overview.

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

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

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

AEP Transmission Holdco

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

AEP River Operations

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

The remainder of our activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The tables below present our reportable segment information for the years ended December 31, 2013, 2012 and 2011 and balance sheet information as of December 31, 2013 and 2012. These amounts include certain estimates and allocations where necessary.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments	C
				(in millions)				
Year Ended December 31, 2013								
Revenues from:								
External Customers	$ 9,347	$ 4,279	$ 27	$ 544	$ 1,208	$ 32	$ (80)(b)	$
Other Operating Segments	645	199	51	19	2,457	57	(3,428)	
Total Revenues	$ 9,992	$ 4,478	$ 78	$ 563	$ 3,665	$ 89	$ (3,508)	$
Asset Impairments and Other Related Charges	$ 72	$ -	$ -	$ -	$ 154	$ -	$ -	$
Depreciation and Amortization	941	591	10	31	236	-	(66)(c)	
Interest Income	7	2	-	-	2	69	(22)	
Carrying Costs Income	14	16	-	-	-	-	-	
Interest Expense	540	292	10	17	55	27	(35)(c)	
Income Tax Expense	398	198	29	7	112	(60)	-	
Net Income	681	358	80	12	228	125	-	

Gross Property Additions	1,822	871	843	7	185	9	(81)

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments	C
				(in millions)				
Year Ended December 31, 2012								
Revenues from:								
External Customers	$ 8,785	$ 4,659	$ 7	$ 647	$ 882	$ 25	$ (60)(b)	$
Other Operating Segments	633	159	17	20	2,585	58	(3,472)	
Total Revenues	$ 9,418	$ 4,818	$ 24	$ 667	$ 3,467	$ 83	$ (3,532)	$
Asset Impairments and Other Related Charges	$ 13	$ -	$ -	$ -	$ 287	$ -	$ -	$
Depreciation and Amortization	873	561	3	29	349	-	(33)(c)	
Interest Income	5	4	-	-	1	22	(24)	
Carrying Costs Income	28	24	1	-	-	-	-	
Interest Expense	520	291	3	17	83	112	(38)(c)	
Income Tax Expense	345	201	17	7	15	19	-	
Net Income (Loss)	803	389	43	15	100	(88)	-	
Gross Property Additions	1,801	664	392	31	249	2	(20)	

Year Ended December 31, 2011	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments
				(in millions)			
Revenues from:							
External Customers	$ 8,942	$ 4,982	$ 3	$ 697	$ 563	$ 24	$ (95)(b)
Other Operating Segments	760	174	5	19	3,331	59	(4,348)
Total Revenues	$ 9,702	$ 5,156	$ 8	$ 716	$ 3,894	$ 83	$ (4,443)
Asset Impairments and Other Related Charges	$ 49	$ -	$ -	$ -	$ 90	$ -	$ -
Depreciation and Amortization	785	549	-	28	304	2	(13)(c)
Interest Income	13	7	-	-	4	22	(19)
Carrying Costs Income	17	376	-	-	-	-	-
Interest Expense	514	293	1	17	87	56	(35)(c)
Income Tax Expense	312	220	2	24	166	94	-
Income (Loss) Before Extraordinary Item	$ 710	$ 404	$ 30	$ 45	$ 439	$ (52)	$ -
Extraordinary Item, Net of Tax	-	373	-	-	-	-	-
Net Income (Loss)	$ 710	$ 777	$ 30	$ 45	$ 439	$ (52)	$ -
Gross Property Additions	$ 1,733	$ 544	$ 263	$ 18	$ 156	$ 219	$ (31)

December 31, 2013	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments (c)
				(in millions)			
Total Property, Plant and Equipment	$ 37,545	$ 12,143	$ 1,636	$ 638	$ 8,277	$ 315	$ (269)
Accumulated Depreciation and Amortization	12,250	3,342	10	189	3,409	173	(85)
Total Property, Plant and Equipment - Net	$ 25,295	$ 8,801	$ 1,626	$ 449	$ 4,868	$ 142	$ (184)
Total Assets	$ 32,791	$ 14,165	$ 2,245	$ 673	$ 6,426	$ 19,645	$ (19,531)(d)
Investments in Equity Method Investees	24	-	480	54	-	11	-

December 31, 2012	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments (c)
				(in millions)			
Total Property, Plant and Equipment	$ 36,066	$ 11,461	$ 748	$ 636	$ 8,529	$ 280	$ (266)
Accumulated Depreciation and Amortization	11,733	3,232	4	161	3,465	168	(72)
Total Property, Plant and Equipment - Net	$ 24,333	$ 8,229	$ 744	$ 475	$ 5,064	$ 112	$ (194)
Total Assets	$ 32,008	$ 13,516	$ 1,216	$ 670	$ 6,664	$ 19,179	$ (18,886)(d)

Investments in Equity Method Investees	24	-	393	43	-	5	-

(a) Corporate and Other includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
(b) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation.
(c) Includes eliminations due to an intercompany capital lease.
(d) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, 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 extent, heating oil, gasoline 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, 2013 and 2012:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2013	Volume December 31, 2012	Unit of Measure
	(in millions)		
Commodity:			
Power	406	498	MWhs
Coal	4	10	Tons
Natural Gas	127	147	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 191	$ 235	USD

Interest Rate and Foreign Currency	$ 820	$ 1,199	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, 2013 and 2012 balance sheets, we netted \$4 million and \$7 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$13 million and \$50 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, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

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	$ 347	$ 12	$ 4	$ 363	$ (203)	$ 160
Long-term Risk Management Assets	368	3	-	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$ 186	$ 1	$ (12)	$ 175	$ 15	$ 190

Fair Value of Derivative Instruments
December 31, 2012

Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities	Gross Amounts Offset in the Statement of Financial	Net Amounts of Assets/Liabilities Presented in the Statement of Financial
		Interest Rate and Foreign			

Balance Sheet Location	Commodity (a)	Commodity (a)	Currency (a)	Recognized	Position (b)	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

(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, 2013, 2012 and 2011:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2013	2012	2011
		(in millions)	
Vertically Integrated Utilities Revenues	$ 15	$ 10	$ 18
Generation & Marketing Revenues	49	50	48
Regulatory Assets (a)	(2)	(43)	(22)
Regulatory Liabilities (a)	(5)	8	(3)
Total Gain (Loss) on Risk Management Contracts	$ 57	$ 25	$ 41

(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 2013, we recognized a loss of $10 million on our hedging instruments and an offsetting gain of $10 million on our long-term debt. During 2012, the fair value changes for both our hedging instruments and hedged long-term debt were immaterial. During 2011, we recognized a gain of $3 million on our hedging instruments and an offsetting loss of $6 million on our long-term debt. For 2013, 2012 and 2011, 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 2013, 2012 and 2011, 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 2013, 2012 and 2011, 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 2013, 2012 and 2011, 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 2013, we did not designate any foreign currency derivatives as cash flow hedges. During 2012 and 2011, we designated foreign currency derivatives as cash flow hedges.

During 2013, 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For 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, 2013, 2012 and 2011, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 7	$ -	$ 7
Hedging Liabilities (a)	6	2	8
AOCI Gain (Loss) Net of Tax	-	(23)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	-	(4)	(4)

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

Interest Rate

	Commodity	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)

(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, 2013, 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 was 44 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.

When we use standardized master agreements, these agreements 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, 2013 and 2012:

	December 31,	
	2013	2012
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 3	$ 7
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	33	32
Amount Attributable to RTO and ISO Activities	28	31

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, 2013 and 2012:

	December 31,	
	2013	2012
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 293	$ 469
Amount of Cash Collateral Posted	1	8
Additional Settlement Liability if Cross Default Provision is Triggered	235	328

11. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities 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, 2013 and 2012 are summarized in the following table:

	December 31, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 18,377	$ 19,672	$ 17,757	$ 20,907

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and Securities Available for Sale, including 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:

Other Temporary Investments	December 31, 2013 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 250	$ -	$ -	$ 250
Fixed Income Securities:				
Mutual Funds	80	-	-	80
Equity Securities - Mutual Funds	12	11	-	23
Total Other Temporary Investments	$ 342	$ 11	$ -	$ 353

Other Temporary Investments	December 31, 2012 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

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

The following table provides the activity for our fixed income and equity securities within Other Temporary Investments for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Proceeds from Investment Sales	$ -	$ -	$ 268
Purchases of Investments	17	2	154
Gross Realized Gains on Investment Sales	-	-	4
Gross Realized Losses on Investment Sales	-	-	-

As of December 31, 2013 and 2012, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2013, fixed income securities were primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

The following is a summary of nuclear trust fund investments as of December 31, 2013 and December 31, 2012:

	December 31, 2013			2012		
	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	$ 19	$ -	$ -	$ 17	$ -	$ -
Fixed Income Securities:						
United States Government	609	26	(4)	648	58	(1)
Corporate Debt	37	2	(1)	35	5	(1)
State and Local Government	255	1	-	270	1	(1)
Subtotal Fixed Income Securities	901	29	(5)	953	64	(3)
Equity Securities - Domestic	1,012	506	(82)	736	285	(77)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,932	$ 535	$ (87)	$ 1,706	$ 349	$ (80)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011

		(in millions)	
Proceeds from Investment Sales	$ 858	$ 988	$ 1,111
Purchases of Investments	910	1,045	1,167
Gross Realized Gains on Investment Sales	18	25	33
Gross Realized Losses on Investment Sales	8	9	22

The adjusted cost of fixed income securities was $872 million and $889 million as of December 31, 2013 and 2012, respectively. The adjusted cost of equity securities was $506 million and $451 million as of December 31, 2013 and 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2013 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 79
1 year – 5 years	384
5 years – 10 years	188
After 10 years	250
Total	$ 901

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, 2013 and 2012. 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, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 16	$ 1	$ -	$ 101	$ 118
Other Temporary Investments					
Restricted Cash (a)	231	8	-	11	250
Fixed Income Securities:					
Mutual Funds	80	-	-	-	80
Equity Securities - Mutual Funds (b)	23	-	-	-	23
Total Other Temporary Investments	334	8	-	11	353
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	22	549	142	(273)	440
Cash Flow Hedges:					
Commodity Hedges (c)	-	15	-	(8)	7
Fair Value Hedges	-	1	-	3	4
De-designated Risk Management Contracts (e)	-	-	-	6	6
Total Risk Management Assets	22	565	142	(272)	457
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	8	-	-	11	19
Fixed Income Securities:					
United States Government	-	609	-	-	609
Corporate Debt	-	37	-	-	37
State and Local Government	-	255	-	-	255
Subtotal Fixed Income Securities	-	901	-	-	901
Equity Securities - Domestic (b)	1,012	-	-	-	1,012
Total Spent Nuclear Fuel and Decommissioning Trusts	1,020	901	-	11	1,932

Total Assets	$ 1,392	$ 1,475	$ 142	$ (149)	$ 2,860
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 30	$ 475	$ 22	$ (282)	$ 245
Cash Flow Hedges:					
Commodity Hedges (c)	-	11	3	(8)	6
Interest Rate/Foreign Currency Hedges	-	2	-	-	2
Fair Value Hedges	-	11	-	3	14
Total Risk Management Liabilities	$ 30	$ 499	$ 25	$ (287)	$ 267

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) (g)	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) (g)	$ 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

(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, 2013 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $4 million in 2014, $(11) million in periods 2015-2017 and $(1) million in periods 2018-2019; Level 2 matures $25 million in 2014, $37 million in periods 2015-2017, $7 million in periods 2018-2019 and $5 million in periods 2020-2030; Level 3 matures $27 million in 2014, $60 million in periods 2015-2017, $14 million in periods 2018-2019 and $19 million in periods 2020-2030. 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, 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.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013, 2012 and 2011.

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, 2013	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2012	$ 86
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(9)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	37
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3)
Purchases, Issuances and Settlements (c)	(16)
Transfers into Level 3 (d) (e)	19
Transfers out of Level 3 (e) (f)	(4)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7
Balance as of December 31, 2013	$ 117

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

(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 tables quantify the significant unobservable inputs used in developing the fair value of our Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High
	(in millions)					
Energy Contracts	$ 132	$ 22	Discounted Cash Flow	Forward Market Price (a)	$ 11.42	$ 120.72
				Counterparty Credit Risk (b)	316	
FTRs	10	3	Discounted Cash Flow	Forward Market Price (a)	(5.10)	10.44
Total	$ 142	$ 25				

Significant Unobservable Inputs
December 31, 2012

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range 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.

12. INCOME TAXES

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

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Federal:			
Current	$ (45)	$ (52)	$ 20
Deferred	676	698	786
Total Federal	631	646	806
State and Local:			
Current	29	35	37

Deferred	24	(77)	(25)
Total State and Local	53	(42)	12
Income Tax Expense	$ 684	$ 604	$ 818

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, 2013	2012	2011
	(in millions)		
Net Income	$ 1,484	$ 1,262	$ 1,949
Extraordinary Item, Net of Tax of $112 million in 2011	-	-	(373)
Income Before Extraordinary Item	1,484	1,262	1,576
Income Tax Expense	684	604	818
Pretax Income	$ 2,168	$ 1,866	$ 2,394
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 759	$ 653	$ 838
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	47	39	41
Investment Tax Credits, Net	(14)	(14)	(15)
Energy Production Credits	-	-	(18)
State and Local Income Taxes, Net	29	(33)	(22)
Removal Costs	(21)	(18)	(20)
AFUDC	(31)	(39)	(42)
Valuation Allowance	5	6	86
U.K. Windfall Tax	(80)	15	-
Other	(10)	(5)	(30)
Income Tax Expense	$ 684	$ 604	$ 818
Effective Income Tax Rate	31.5 %	32.4 %	34.2 %

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

	December 31, 2013	2012
	(in millions)	
Deferred Tax Assets	$ 2,900	$ 2,900
Deferred Tax Liabilities	(13,088)	(12,098)
Net Deferred Tax Liabilities	$ (10,188)	$ (9,198)
Property Related Temporary Differences	$ (7,508)	$ (6,752)
Amounts Due from Customers for Future Federal Income Taxes	(273)	(289)
Deferred State Income Taxes	(765)	(683)
Securitized Assets	(870)	(780)
Regulatory Assets	(609)	(781)
Deferred Income Taxes on Other Comprehensive Loss	66	184
Accrued Nuclear Decommissioning	(554)	(475)
Net Operating Loss Carryforward	233	194

Tax Credit Carryforward	109	104
Valuation Allowance	(97)	(92)
All Other, Net	80	172
Net Deferred Tax Liabilities	$ (10,188)	$ (9,198)

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 2011. 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 and was completed in the second quarter of 2013. 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. However, it is possible 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. We are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

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)	
Indiana	$ 50	2033
Louisiana	428	2028
Oklahoma	241	2033
Tennessee	9	2026
Virginia	301	2031
West Virginia	725	2032

As a result, we recognized deferred federal, state and local income tax benefits in 2012 and 2011. As of December 31, 2013, we have $156 million of unrealized federal net operating loss carryforward tax benefits. We anticipate future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2032. We also anticipate future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the state carryforward expires for each state.

At the end of 2013 and 2012, we had $121 million of uncertain tax positions netted against the federal net operating loss carryforward tax benefits.

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, 2013, we have total federal tax credit carryforwards of $108 million and total state tax credit carryforwards of $98 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $74 million will expire in the years 2028 through 2032 and the state coal tax credits of $29 million will expire in the years 2014 through 2022.

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 determine 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. The positive evidence we considered is the history of positive pretax income and the fact that the tax losses resulted from temporary differences that will reverse in future periods. On the basis of the evaluation of all available positive and negative evidence, as of December 31, 2013, a valuation allowance of $41 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to recognize only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted.

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 7.

Uncertain Tax Positions

In May 2013, the U.S. Supreme Court decided that the U.K. Windfall Tax imposed upon U.K. electric companies privatized between 1984 and 1996 is a creditable tax for U.S. federal income tax purposes. We filed protective claims asserting the creditability of the tax, dependent upon the outcome of the case. As a result of the favorable U.S. Supreme Court decision, we recognized a tax benefit of $80 million, plus $43 million of pretax interest income in the second quarter of 2013. The tax benefit and interest income resulted in an increase in net income of $108 million, but did not result in the receipt of cash in 2013.

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,		
	2013	2012	2011
		(in millions)	
Interest Expense	$ 1	$ 11	$ 8
Interest Income	51	-	22
Reversal of Prior Period Interest Expense	-	1	13

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

	December 31,	
	2013	2012
	(in millions)	

Accrual for Receipt of Interest	$	43	$	-
Accrual for Payment of Interest and Penalties		5		7

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

	2013	2012	2011
		(in millions)	
Balance as of January 1,	$ 267	$ 168	$ 219
Increase - Tax Positions Taken During a Prior Period	-	23	51
Decrease - Tax Positions Taken During a Prior Period	(94)	(16)	(43)
Increase - Tax Positions Taken During the Current Year	2	121	10
Decrease - Tax Positions Taken During the Current Year	-	-	-
Decrease - Settlements with Taxing Authorities	-	(25)	(31)
Decrease - Lapse of the Applicable Statute of Limitations	-	(4)	(38)
Balance as of December 31,	$ 175	$ 267	$ 168

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $87 million, $149 million and $111 million for 2013, 2012 and 2011, 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 Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of 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 did have a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate 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 rate of 6%, effective January 1, 2012.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for remaining periods up to 36 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:

Lease Rental Costs	Years Ended December 31, 2013	2012	2011
		(in millions)	
Net Lease Expense on Operating Leases	$ 327	$ 346	$ 343
Amortization of Capital Leases	74	73	72
Interest on Capital Leases	28	29	32
Total Lease Rental Costs	$ 429	$ 448	$ 447

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.

Property, Plant and Equipment Under Capital Leases	December 31, 2013	2012
	(in millions)	
Generation	$ 103	$ 117
Other Property, Plant and Equipment	627	495
Total Property, Plant and Equipment Under Capital Leases	730	612
Accumulated Amortization	197	173
Net Property, Plant and Equipment Under Capital Leases	$ 533	$ 439
Obligations Under Capital Leases		
Noncurrent Liability	$ 428	$ 375
Liability Due Within One Year	110	74
Total Obligations Under Capital Leases	$ 538	$ 449

Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2014	$ 135	$ 288
2015	111	268
2016	97	246
2017	79	230
2018	44	215

Later Years	215	862
Total Future Minimum Lease Payments	681	$ 2,109
Less Estimated Interest Element	143	
Estimated Present Value of Future Minimum Lease Payments	$ 538	

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, 2013, the maximum potential loss for these lease agreements was approximately $20 million assuming the fair value of the equipment is zero at the end of the lease term.

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, 2013 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2014	$ 74	$ 74
2015	74	74
2016	74	74
2017	74	74
2018	74	74
Later Years	295	295
Total Future Minimum Lease Payments	$ 665	$ 665

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 $13 million and $15 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2013. 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 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are approximately $9 million and $10 million for I&M and SWEPCo, respectively, 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 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, 2013 and 2012 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, 2013 and 2012 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 November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio Trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future payment obligations of $110 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2013 balance sheet. The future minimum lease payments for the sale-and-leaseback transaction as of December 31, 2013 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**I&M**
	(in millions)
2014	$ 43
2015	32
2016	27
2017	6
2018	2
Total Future Minimum Lease Payments	$ 110

14. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2013, 2012 and 2011:

Shares of AEP Common Stock	**Issued**	**Held in Treasury**
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
Issued	2,109,002	-
Balance, December 31, 2013	508,113,964	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, 2013 and 2012:

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	2012	Outstanding as of December 31, 2013	2012
				(in millions)	
Senior Unsecured Notes (a)					
2013-2043	5.45%	1.65%-8.13%	0.685%-8.13%	$ 11,799	$ 12,712
Pollution Control Bonds (b)					
2013-2038 (c)	3.29%	0.02%-6.30%	0.11%-6.30%	1,932	1,958
Notes Payable (d)					
2013-2032	4.17%	1.164%-8.03%	1.913%-8.03%	369	427
Securitization Bonds (e)					
2013-2031	3.72%	0.88%-6.25%	0.88%-6.25%	2,686	2,281
Spent Nuclear Fuel Obligation (f)				265	265
Other Long-term Debt (a) (g)					
2015-2059	1.41%	1.15%-13.718%	1.72%-13.718%	1,360	140
Fair Value of Interest Rate Hedges				(9)	3
Unamortized Discount, Net				(25)	(29)
Total Long-term Debt Outstanding				18,377	17,757
Long-term Debt Due Within One Year				1,549	2,171
Long-term Debt				$ 16,828	$ 15,586

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to APCo and KPCo in the amounts of $300 million and $200 million, respectively, upon AGR's transfer of certain of those generation assets.

(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 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 2013, APCo and OPCo issued $380 million and $267 million, respectively, of Securitization Bonds (see Note 16).
(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 6).
(g) In 2013, PSO, TCC and TNC issued $50 million, $100 million and $75 million three-year credit facilities, respectively, to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	2015	2016	2017	2018	After 2018	Total
				(in millions)			
Principal Amount	$ 1,549	$ 2,519	$ 1,147	$ 1,724	$ 1,135	$ 10,328	$ 18,402
Unamortized Discount, Net							(25)
Total Long-term Debt Outstanding							$ 18,377

In January 2014 and February 2014, I&M retired $5 million and $19 million, respectively, of Notes Payable related to DCC Fuel.

In January 2014, TCC retired $112 million of its outstanding Securitization Bonds.

In January 2014, OPCo retired $225 million of 4.85% Senior Unsecured Notes due in 2014.

As of December 31, 2013, trustees held, on our behalf, $500 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, 2013, 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, 2013, we had credit facilities totaling $3.5 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2013 was $904 million and the weighted average interest rate of commercial paper outstanding during 2013 was 0.32%. Our outstanding short-term debt was as follows:

	December 31,			
	2013		2012	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 700	0.23 %	$ 657	0.26 %
Commercial Paper	57	0.29 %	321	0.42 %
Line of Credit – Sabine (c)	-	- %	3	1.82 %
Total Short-term Debt	$ 757		$ 981	

(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 6.

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 June 2013, we amended our receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. We amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2013	2012	2011
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.23 %	0.26 %	0.27 %
Net Uncollectible Accounts Receivable Written Off	$ 35	$ 29	$ 37

	December 31,	
	2013	2012
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 929	$ 835
Total Principal Outstanding	700	657
Delinquent Securitized Accounts Receivable	45	37
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	16	21
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	331	316

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

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards 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, 2013, 15,973,699 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 2013, 2012 or 2011 but we did have outstanding stock options from grants in earlier periods that were exercised in these years. As of December 31, 2013 we have no outstanding stock options. 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, 2013	2012	2011
	(in thousands)		
Intrinsic Value of Options Exercised (a)	$ 3,105	$ 1,699	$ 1,202

(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, 2013, 2012 and 2011 is as follows:

	2013		2012		2011	
	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,	188	$ 30.17	321	$ 29.35	551	$ 32.88
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(187)	30.18	(128)	28.21	(104)	27.39
Forfeited/Expired	(1)	27.95	(5)	27.26	(126)	46.40
Outstanding as of December 31,	-	NA	188	30.17	321	29.35
Options Exercisable as of December 31,	-	$ NA	188	$ 30.17	321	$ 29.35

NA Not applicable.

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, 2013, 2012 and 2011 as follows:

	Years Ended December 31,		
Performance Units	**2013**	**2012**	**2011**
Awarded Units (in thousands)	1,284	546	7

		2013		2012		2011
Weighted Average Unit Fair Value at Grant Date	$	46.23	$	41.38	$	38.39
Vesting Period (in years)		3		3		3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	**Years Ended December 31,**					
		2013		**2012**		**2011**
Awarded Units (in thousands)		101		138		198
Weighted Average Grant Date Fair Value	$	45.42	$	40.97	$	37.31
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. Starting with 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 periods ended December 31, 2013, 2012 and 2011 were as follows:

Performance Units	Years Ended December 31, 2013	2012	2011
Certified Performance Score	118.8 %	99.7 %	89.8 %
Performance Units Earned	749,219	1,096,572	1,216,926
Performance Units Mandatorily Deferred as AEP Career Shares	72,883	51,056	52,639
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	39,691	26,337	42,502
Performance Units to be Paid in Cash	636,645	1,019,179	1,121,785

The cash payouts for the years ended December 31, 2013, 2012 and 2011 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Cash Payouts for Performance Units	$ 43,925	$ 44,968	$ 15,985
Cash Payouts for AEP Career Share Distributions	3,675	11,027	2,777

Restricted Shares and Restricted Stock Units

In 2004, the independent members of the AEP Board of Directors granted restricted shares to the then Chairman, President and CEO upon the commencement of his AEP employment. The final 66,667 shares 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. Upon vesting, RSUs are converted into a share of AEP common stock, with the exception of participants subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, who are paid in cash. For awards that are settled with shares, 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. For awards that are paid in cash, compensation cost is recorded over the vesting period and adjusted for changes in value until vested. The fair value at vesting is determined by multiplying the number of units vested by the 20-day average closing price of AEP common stock. 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. Of these RSUs, 55,172 vested on August 3, 2013 and 110,348 remain outstanding, excluding dividends.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2013, 2012 and 2011 as follows:

Restricted Stock Units	Years Ended December 31, 2013	2012	2011
Awarded Units (in thousands)	644	497	121
Weighted Average Grant Date Fair Value	$ 46.24	$ 40.69	$ 37.07

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2013, 2012 and 2011 were as follows:

Restricted Shares and Restricted Stock Units	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 15,325	$ 10,608	$ 7,164
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	20,378	12,157	8,017

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

A summary of the status of our nonvested RSUs as of December 31, 2013 and changes during the year ended December 31, 2013 are as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2013	1,000	$ 38.22
Granted	644	46.24
Vested	(408)	37.57
Forfeited	(31)	39.97
Nonvested as of December 31, 2013	1,205	42.64

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2013 was $56 million and the weighted average remaining contractual life was 2.09 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. 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, 2013, 2012 and

2011.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2013, 2012 and 2011 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2013	2012	2011
Awarded Units (in thousands)	33	52	52
Weighted Average Grant Date Fair Value	$ 45.81	$ 41.20	$ 37.72

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2013, 2012 and 2011 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 56,352	$ 51,767	$ 61,807
Actual Tax Benefit Realized	19,723	18,119	12,632
Total Compensation Cost Capitalized	13,165	10,707	11,608

(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, 2013, 2012 and 2011, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2013, there was $105 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 1.66 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, 2013, 2012 and 2011 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Cash Received from Stock Options Exercised	$ 5,659	$ 3,598	$ 2,855
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	1,040	618	411

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.

16. 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, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and our protected cell of EIS 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, 2013, 2012 and 2011 were $155 million, $147 million and $128 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI 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, 2013, 2012 and 2011 were $153 million, $127 million and $85 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. In October 2013, the lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC. 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 concluded that we are the primary beneficiary and are required to consolidate AEP Credit. 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 14.

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 billion and $2.3 billion as of December 31, 2013 and 2012, respectively. Transition Funding has securitized transition assets of $1.9 billion and $2.1 billion as of December 31, 2013 and 2012, respectively. 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.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $267 million as of December 31, 2013. Ohio Phase-in-Recovery Funding has securitized assets of $132 million as of December 31, 2013. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on the balance sheet.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $380 million as of December 31, 2013. Appalachian Consumer Rate Relief Funding has securitized assets of $369 million as of December 31, 2013. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on the balance sheet.

The securitized bonds of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in current and long-term debt on the balance sheets. The securitized assets of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in securitized assets 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 EIS. Our insurance premium expense to the protected cell for the years ended December 31, 2013, 2012 and 2011 were $31 million, $32 million and $48 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.

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, 2013
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding	Protected Cell of EIS
ASSETS							
Current Assets	$ 67	$ 118	$ 935	$ 232	$ 23	$ 6	$ 143
Net Property, Plant and Equipment	157	157	-	-	-	-	-
Other Noncurrent Assets	51	60	1	1,918 (a)	252 (b)	378 (c)	3
Total Assets	$ 275	$ 335	$ 936	$ 2,150	$ 275	$ 384	$ 146
LIABILITIES AND EQUITY							
Current Liabilities	$ 33	$ 108	$ 827	$ 312	$ 37	$ 14	$ 39
Noncurrent Liabilities	242	227	1	1,820	237	368	66
Equity	-	-	108	18	1	2	41
Total Liabilities and Equity	$ 275	$ 335	$ 936	$ 2,150	$ 275	$ 384	$ 146

(a) Includes an intercompany item eliminated in consolidation of $82 million.
(b) Includes an intercompany item eliminated in consolidation of $116 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	Protected Cell of EIS
ASSETS					
Current Assets	$ 57	$ 133	$ 843	$ 250	$ 130
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	1	2,167 (a)	4

Total Assets	$ 282	$ 401	$ 844	$ 2,417	$ 134
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 121	$ 800	$ 304	$ 43
Noncurrent Liabilities	250	280	1	2,095	66
Equity	-	-	43	18	25
Total Liabilities and Equity	$ 282	$ 401	$ 844	$ 2,417	$ 134

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

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, 2013, 2012 and 2011 were $60 million, $77 million and $62 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,			
	2013		2012	
	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	-	61	-	49
Total Investment in DHLC	$ 9	$ 70	$ 9	$ 58

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 September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The settlement proceedings are ongoing.

Our investment in PATH-WV was:

	December 31,			
	2013		2012	
	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	6	6	12	12
Total Investment in PATH-WV	$ 25	$ 25	$ 31	$ 31

As of December 31, 2013, our $25 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

17. 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:

2013	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
	(in millions)			(in years)	(in millions)		
Generation	$ 17,873	$ 7,168	1.7 - 3.7 %	31 - 132	$ 7,201	$ 2,969	2.6 - 3.3 %
Transmission	10,854	2,805	1.1 - 2.7 %	25 - 87	39	16	2.5 %
Distribution	16,377	3,988	2.3 - 3.8 %	11 - 75	-	-	NA
CWIP	2,326	(121)	NM	NM	145	1	NM
Other	4,116	1,931	2.0 - 7.9 %	5 - 75	1,354	531	NM
Total	$ 51,546	$ 15,771			$ 8,739	$ 3,517	

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

2011	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	2.6 - 3.5 %	20 ¯ 66
Transmission	1.3 - 2.7 %	25 - 87	NA	NA
Distribution	2.4 - 4.0 %	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	1.7 - 9.3 %	5 - 55	NM	NM

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 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 2013 and 2012 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
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
Accretion Expense	103
Liabilities Incurred	4
Liabilities Settled	(22)
Revisions in Cash Flow Estimates	54
ARO as of December 31, 2013	$ 1,835

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

As of December 31, 2013 and 2012, our ARO liability included $1.2 billion and $1.2 billion, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2013 and 2012, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.6 billion and $1.4 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,		
	2013	**2012**	**2011**
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 73	$ 93	$ 98
Allowance for Borrowed Funds Used During Construction	40	69	63

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, 2013		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station, Unit 4 (b)	Coal	43.5 %	335	2	55
J.M. Stuart Generating Station (c)	Coal	26.0 %	544	11	190
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	809	2	399
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2 %	262	47	198
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0 %	123	54	66
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9 %	519	29	376
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3 %	404	7	223
Turk Generating Plant (e)	Coal	73.33 %	1,638	13	35
Transmission	NA	(g)	78	-	50
Total			$ 4,712	$ 165	$ 1,592

			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 6 (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station, Unit 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 1 (d)	Lignite	40.2 %	263	8	195
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0 %	121	14	64
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9 %	514	16	371
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3 %	403	4	216
Turk Generating Plant (e)	Coal	73.33 %	1,613	(3)	-
Transmission	NA	(g)	69	4	50
Total			$ 4,642	$ 82	$ 1,523

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of Beckjord Plant, Unit 6 was impaired in the fourth quarter of 2012. See "Impairments" section of Note 7.
(b) Operated by AGR.
(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) Varying percentages of ownership.
NANot applicable.

18. 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 facilitate an organizational and process evaluation and a second firm to evaluate our current employee benefit programs. The process resulted in involuntary severances and was 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 of $47 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

	Sustainable Cost Reduction Activity	
	(in millions)	
Balance as of December 31, 2012	$	25
Incurred		16
Settled		(31)
Adjustments		(9)
Balance as of December 31, 2013	$	1

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Of the current period expense, approximately 43% was within the Generation & Marketing segment, 36% was within the Transmission and Distribution Utilities segment and 18% was within the Vertically Integrated Utilities segment. Of the total cumulative expense, approximately 51% was within the Vertically Integrated Utilities segment, 27% was within the Transmission and Distribution Utilities segment and 19% was within the Generation & Marketing segment. The remaining liability is included in Other Current Liabilities on the balance sheets. We do not expect additional costs to be incurred related to this initiative.

19. 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:

	2013 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,826	$ 3,582	$ 4,176	$ 3,773
Operating Income	755	547 (a)	875 (c)	678 (d) (e)
Net Income	364	339 (a) (b)	434 (c)	347 (d) (e)
Amounts Attributable to AEP Common Shareholders:				
Net Income	363	338 (a) (b)	433 (c)	346 (d) (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.75	0.69	0.89	0.71
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.75	0.69	0.89	0.71

	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 (g) (h)
Net Income	390	363	488	21 (g) (h)
Amounts Attributable to AEP Common Shareholders:				
Net Income	389	362	487	21 (g) (h)
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

(a) Includes an impairment for Muskingum River Plant, Unit 5 (see Note 7).
(b) Includes U.K. Windfall Tax benefit (see Note 12).
(c) Includes regulatory disallowances for the Turk Plant (see Note 4) and for Big Sandy Plant, Unit 2 (see Note 7).
(d) Includes a regulatory disallowance for Amos Plant, Unit 3 (see Note 7).
(e) Includes the reversal of regulatory disallowance for the Turk Plant (see Note 4).
(f) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(g) Includes impairments for certain Ohio generation plants (see Note 7).
(h) See Note 18 for discussion of cost reduction programs in 2012.

20. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2013 and 2012 by operating segment are as follows:

	Vertically Integrated Utilities	AEP River Operations	Generation and Marketing	AEP Consolidated
		(in millions)		
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
Impairment Losses	-	-	-	-
Balance as of December 31, 2013	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2013 and 2012, 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 $10 million as of December 31, 2013, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. 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,			
		2013		2012	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Acquired Customer Contracts	5	$ 58	$ 48	$ 58	$ 34

Amortization of intangible assets was $14 million, $34 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Our estimated total amortization is $6 million, $3 million and $1 million for 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; or Julie Sherwood, 614-716-2663, jasherwood@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of February 24, 2014, there were approximately 77,500 registered shareholders and approximately 446,000 shareholders holding stock in street name through a bank or broker. There were 487,820,462 shares outstanding as of February 24, 2014.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2013. 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	53	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	48	Executive Vice President – Transmission
David M. Feinberg	44	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	53	Senior Vice President and Chief Administrative Officer
Mark C. McCullough	54	Executive Vice President – Generation
Robert P. Powers	59	Executive Vice President and Chief Operating Officer
Brian X. Tierney	46	Executive Vice President and Chief Financial Officer
Dennis E. Welch	62	Executive Vice President and Chief External Officer