AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 25, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2013
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

Yes X No

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

X Accelerated filer

Large accelerated filer			
Non-accelerated filer		Smaller reporting company	

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

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

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

Yes	No	X

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants as of October 24, 2013
American Electric Power Company, Inc.	487,290,382
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2013

Part II. OTHER INFORMATION

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holding Company	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	American Electric Power Transmission Company, a wholly-owned subsidiary of AEP Transmission Holding Company.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.

DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP 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, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NOx	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
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.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.

Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.

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Rockport Plant	A generating plant, consisting of two 1,300 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.
SO2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
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” of the 2012 Annual Report, 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 future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
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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 generating 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 and the legal separation of generation in Ohio, including the implementation of ESPs and the successful approval, where applicable, and transfer of such Ohio generation assets and liabilities to regulated and nonregulated entities at book value.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of the 2012 Annual Report and in Part II of this report.

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

EXECUTIVE OVERVIEW

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value (NBV) to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. 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 October 2013, OPCo filed an application with the PUCO to amend the corporate separation plan by permitting OPCo to retain certain rights to purchase power from OVEC.

Also in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at NBV approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at NBV OPCo's current two-thirds ownership in Amos Plant, Unit 3 to APCo and transfer at NBV OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests. In December 2012, APCo and KPCo filed requests with their respective commissions for the approval of these plant transfers.

In April 2013, the FERC issued orders approving the merger of APCo and WPCo and approving the transfer of OPCo's generation assets to AEPGenCo and the Amos Plant and Mitchell Plant asset transfers to APCo and KPCo, to be effective using our requested date of December 31, 2013. In May 2013, the IEU petitioned the FERC for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AEPGenCo. OPCo has contested the petition for rehearing, which remains pending before the FERC. In July 2013, the Virginia SCC approved the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo but, for rate purposes, reduced the proposed transfer price by $83 million pretax. Additionally, the Virginia SCC denied the proposed transfer of OPCo's one-half interest in the Mitchell Plant to APCo. APCo plans to pursue cost recovery of the transferred interest in the Amos Plant in Virginia in the 2014 biennial filing. Management is currently evaluating the implications of this order while awaiting a final decision from the WVPSC. Hearings in the plant transfer case were held at the WVPSC in July 2013. In September 2013, a WVPSC staff brief advocated for the approval of the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo, also at a reduced amount for rate purposes, and the denial of the proposed transfer of OPCo's one-half interest in the Mitchell Plant to APCo. Any disallowance related to recovery of Amos Plant, Unit 3, as a result of Virginia SCC or WVPSC orders, would be recorded upon the transfer, expected in the fourth quarter of 2013. In October 2013, the KPSC issued an order approving a modified settlement agreement that included a limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by the pending WVPSC order. Additionally, the order rejected our request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in the third quarter of 2013, KPCo recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statement of income. See the "Plant Transfers" sections of APCo and WPCo Rate Matters and KPCo Rate Matters in Note 3 and the "2013 Kentucky Base Rate Case" section below.

The AEP East Companies also requested FERC approval, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' 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. In March 2013, a revised PCA was filed at the FERC that included certain clarifying wording changes agreed upon by intervenors. A decision is pending at the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of Note 3.

Additionally, FERC approval was sought for a power supply agreement between AEPGenCo and OPCo. This agreement provides for AEPGenCo 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 an auction from January 1, 2014 through December 31, 2014.

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In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by recent 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. 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 corporate separation is approved as filed, for any AEPGenCo generation not serving OPCo's retail load, AEPGenCo's results of operations will be largely determined by prevailing market conditions effective January 1, 2014. If incurred costs are not ultimately recovered, it could reduce future net income and cash flows and impact financial condition.

Ohio Electric Security Plan Filing

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 September 30, 2013, OPCo's net deferred fuel balance was $467 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 up to the total 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, which 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. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio. As of September 30, 2013, OPCo's incurred deferred capacity costs balance was $228 million, including debt carrying costs.

As part of the August 2012 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the 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.

In June 2013, intervenors in the competitive bid process (CBP) docket filed recommendations that include prospective rate reductions for capacity and non-energy FAC issues. OPCo maintains that the August 2012 ESP order fixed OPCo's non-energy generation rates through December 31, 2014 and ordered the application of a $188.88/MW day price for capacity for non-shopping customers effective January 1, 2015. However, intervenors maintained that OPCo's non-energy generation rates should be reduced prior to January 1, 2015 to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned (10% prior to June 2014 and 60% for the period June 1, 2014 through December 31, 2014). Depending upon actual customer switching levels and the timing of the auctions, OPCo estimates that these capacity issues could reduce OPCo's projected future revenues by up to approximately $155 million for the period January 2014 through May 2015, if adopted by the PUCO. An additional proposal to prospectively offset deferred capacity costs based upon the results of the energy-only auctions was not quantified and OPCo maintains that proposal should not be adopted in light of prior PUCO orders. Hearings related to the CBP were held at the PUCO in June and July 2013. A decision from the PUCO is pending.

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 3.

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) Retail Stability Rider collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation and Marketing segment which targets retail customers, both within and outside of our retail service territory.

Customer Demand

In comparison to 2012, our weather-normalized retail sales were down 1.5% and 1.9% for the three and nine months ended September 30, 2013, respectively. Our industrial sales declined 3.9% and 5.1%, respectively, partially due to lower production levels at Ormet, a large aluminum company. Ormet has a contract to purchase power from OPCo through 2018. In October 2013, Ormet announced that it is unable to emerge from bankruptcy and that it has 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.

PJM Capacity Market

If corporate separation and asset transfers are approved as filed, AEPGenCo will be subject to the PJM capacity auction prices after May 2015 for the majority of the current OPCo-owned generation assets. Under the previously approved June 2012 – May 2015 ESP, OPCo is allowed to receive revenues through May 2015 for the generation assets from base generation rates and allowed to defer incurred capacity costs not recovered from CRES providers up to \$188.88/MW day. The PJM base capacity price for the planning year June 2015 through May 2016 was previously announced as \$136.00/MW day. In May 2013, PJM announced the base capacity auction price for the June 2016 through May 2017 planning period would be \$59.37/MW day.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO’s 2009 order. In October 2013, the PUCO issued an order on the 2010 SEET filing. As a result, the PUCO ordered a \$7 million refund of pretax earnings to customers. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 for OPCo. Additionally, management does not currently believe that there will be significantly excessive earnings in 2013 for OPCo. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition. See the “Ohio Electric Security Plan Filing” section of Note 3.

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 September 30, 2013, SWEPCo’s share of incurred construction expenditures for the Turk Plant was approximately \$1.8 billion, including AFUDC and capitalized interest of \$328 million and related transmission costs of \$118 million. As of September 30, 2013, a provision of \$173 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total capitalized expenditures of \$1.6 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. The Arkansas portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the "Turk Plant" section of Note 3.

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million 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 of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge (ALJ) issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In May 2013, the ALJ issued a proposal for decision recommending a rate increase but found SWEPCo imprudent for failing to cancel the Turk Plant in 2010.

The PUCT rejected the ALJ's imprudence recommendation, but during a September 2013 open meeting, the PUCT stated that it would limit the recovery of the investment in the Turk Plant by imposing a Texas jurisdictional cost cap established in the recently concluded Certificate of Convenience and Necessity (CCN) case appeal (the Texas capital cost cap). The PUCT also provided new details on how the cost cap would be applied. In October 2013, the PUCT issued an order with the determination that the Turk Plant 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 impairment of $111 million in Asset Impairments and Other Related Charges on the statement of income. The order approved an annual rate increase of approximately $39 million based upon a return on common equity of 9.65%. As a result of this approval, SWEPCo retroactively applied these rates back to the end of January 2013. The approval also provided for the following: (a) no disallowances to the existing book investment in the Stall Plant, and (b) the exclusion, until SWEPCo files and obtains approval of a Transmission Cost Recovery Rider, of the Turk Plant transmission line investment that was not in service at the end of the test year. Additionally, the PUCT determined that it would defer consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. Requests for rehearing may be filed within 30 days of receipt of the PUCT order. SWEPCo intends to file a motion for rehearing with the PUCT in late October 2013.

If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Turk Plant, transmission lines or Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition. See the "2012 Texas Base Rate Case" section of Note 3.

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 prudence review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence 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 3.

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 to $92 million. In March 2013, the Indiana Office of Utility Consumer

Counselor (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 certain aspects of the rate case. If the 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 3.

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 includes cost recovery of the pending transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order which modified and approved a settlement agreement relating to the proposed transfer of the one-half interest in the Mitchell Plant, in which KPCo agreed to withdraw this base rate case request. KPCo intends to withdraw this base rate request following the resolution of any potential requests for rehearing or appeals of the KPSC order. Assuming KPCo withdraws the base rate case, current base rates will remain in effect until at least May 2015.

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 extended 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 September 30, 2013, I&M has incurred $285 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 in a base rate case. I&M was granted recovery through an LCM rider which will be determined by a proceeding in the fourth quarter of 2013 and semi-annual proceedings thereafter. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in its rates. In October 2013, I&M filed an application with the IURC for LCM rider rates to be effective January 2014.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to certain 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 3.

Repositioning Efforts

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. This process has 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 ongoing review of repositioning opportunities continues to yield cost savings for many of our subsidiaries, allowing us to direct many of these savings into growth 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 3 – Rate Matters, Note 5 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2012 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to 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 Federal 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. In October 2013, we filed a motion to dismiss the case. 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 SO2, NOx, 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 CO2 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.

See a complete discussion of these matters in the "Environmental Issues" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2012 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. 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 September 30, 2013, the AEP System had a total generating capacity of 37,600 MWs, of which 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 and our current plan for corporate separation effective January 1, 2014, investments to meet these proposed requirements range from approximately \$3.5 billion to \$4 billion from 2013 through 2020 including amounts related to nonregulated plants. These amounts include investments to convert some of our coal generation units to natural gas. If natural gas conversion is not completed, the 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/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-4	995
KPCo	Big Sandy Plant, Unit 2	800
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-5	1,440
OPCo	Picway Plant	100
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of September 30, 2013, the net book value of all of OPCo's units above was zero and 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.

In the second quarter of 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 the second quarter of 2013, we completed an impairment analysis and recorded a $154 million pretax ($99 million, net of tax) impairment charge for OPCo'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 5.

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)
APCo	Clinch River Plant, Units 1-2	470
I&M/AEGCo/KPCo	Rockport Plant, Units 1-2	2,620
KPCo	Big Sandy Plant, Unit 1	278
PSO	Northeastern Station, Unit 3	460
SWEPCo	Welsh Plant, Units 1 & 3	1,056
Total		4,884

As of September 30, 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 $1.4 billion.

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 SO2 and NOx 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 SO2 emission caps for the AEP System and additional mitigation measures. The Federal EPA sought public comments on the modification prior to its entry by the court in May 2013. For the units of the Rockport Plant, the modified decree requires installation of dry sorbent injection technology for SO2 control on both units in 2015 and imposes a declining plant-wide cap on SO2 emissions beginning in 2016.

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 July 2013, a settlement agreement was filed with the IURC. The settlement agreement includes 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. A hearing was held at the IURC in August 2013 and a decision is expected by November 2013. As of September 30, 2013, we have incurred costs of $93 million related to the CCT Project, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it could reduce future net income and cash flows. See the "Rockport Plant Clean Coal Technology Project (CCT Project)" section of Note 3.

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 September 30, 2013, the net book values of NES, Units 3 and 4 were $182 million and $101 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.

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 September 30, 2013, SWEPCo has incurred $17 million in costs related to these projects. Management intends to seek recovery of these projects from SWEPCo's state commissions.

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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 a Clean Air Visibility Rule (CAVR), detailing the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the Cross-State Air Pollution Rule (CSAPR) trading programs to use those programs in place of source-specific BART for SO2 and NOx 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.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO2, NOx 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 August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO2 and NOx allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances was allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NOx program in the rule. Texas is subject to the annual programs for SO2 and NOx in addition to the seasonal NOx program. The annual SO2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NOx program. The supplemental rule was finalized in December 2011 with an increased NOx 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 December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the 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 (HAPs) Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In 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. Revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions, were issued by the Federal EPA in March 2013. The Federal EPA has reopened the public comment period to consider 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 startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the 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 proceeding on the remaining issues and briefing was completed in April 2013.

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 NOx control measures in the SIP and disapprove the SO2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA proposed a FIP that would require these units to install technology capable of reducing SO2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement. A revised regional haze SIP has been adopted by the State of Oklahoma. The Federal EPA proposed approval of the revised SIP.

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CO2 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 with the option to meet the tighter limits if they choose to average emissions over multiple years. 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 CO_2 emission 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. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities. In October 2013, the U.S. District Court for the District of Columbia issued an order stating that it intended to partially rule in favor of the Federal EPA for dismissal of two counts and rule in favor of the environmental organizations on one count. However, the court also stated that a Memorandum Opinion and Final Order would be forthcoming and until issued we are unable to predict the impact of the court's ruling.

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 not expected until November 2013. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule 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 will 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.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a “public nuisance” and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We are no longer a party to any such cases. See Note 4.

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

For additional information on climate change, other environmental issues and the actions we are taking to address potential impacts, see Part I of the 2012 Form 10-K under the headings entitled “Business – General – Environmental and Other Matters” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Utility Operations

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

Transmission Operations

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

AEP River Operations

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

Generation and Marketing

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

The table below presents Net Income by segment for the three and nine months ended September 30, 2013 and 2012.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in millions)			
Utility Operations	$ 409	$ 471	$ 980	$ 1,220
Transmission Operations	22	14	53	31
AEP River Operations	(1)	(1)	(12)	11
Generation and Marketing	4	10	15	4
All Other (a)	-	(6)	101	(25)
Net Income	$ 434	$ 488	$ 1,137	$ 1,241

(a) While not considered a reportable segment, All Other includes Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

AEP CONSOLIDATED

Third Quarter of 2013 Compared to Third Quarter of 2012

Net Income decreased from $488 million in 2012 to $434 million in 2013 primarily due to:

- Impairments during the third quarter of 2013 for the following:
  - A decision by the PUCT determining that AFUDC on the Turk Plant was included in the Texas capital cost cap.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- A decrease in weather-related usage.
- The loss of retail customers in Ohio to various CRES providers.

These decreases were partially offset by:

- Successful rate proceedings in various jurisdictions.
- The deferral of Ohio capacity costs as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.
- A decrease in Ohio depreciation expense due to the impairments of certain Ohio generation plants.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Net Income decreased from $1,241 million in 2012 to $1,137 million in 2013 primarily due to:

- Impairments during 2013 for the following:
  - Muskingum River Plant, Unit 5.
  - A decision by the PUCT determining that AFUDC on the Turk Plant was included in the Texas capital cost cap.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- The loss of retail customers in Ohio to various CRES providers.
- A decrease in margins from off-system sales primarily due to lower CRES capacity revenues as a result of Reliability Pricing Model pricing effective August 2012, lower PJM capacity revenues and reduced trading and marketing margins.
- An increase in plant outages during 2013.
- A decrease in AEP River Operations' 2013 earnings due to unfavorable operating conditions caused by extremely low water levels in the first quarter of 2013 followed by flood conditions later in the spring as well as significant reductions in grain and export coal demand.
- A decrease due to OPCo's second quarter 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
- An increase in other variable electric generation expenses during 2013.

These decreases were partially offset by:

- Successful rate proceedings in various jurisdictions.
- The deferral of Ohio capacity costs as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.
-

A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

· A decrease in Ohio depreciation expense due to the impairments of certain Ohio generation plants.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross Margin represents total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased electricity.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in millions)			
Revenues	$ 3,819	$ 3,839	$ 10,614	$ 10,482
Fuel and Purchased Electricity	1,368	1,401	3,775	3,766
Gross Margin	2,451	2,438	6,839	6,716
Other Operation and Maintenance	802	858	2,487	2,383
Asset Impairments and Other Related Charges	144	13	298	13
Depreciation and Amortization	433	458	1,268	1,318
Taxes Other Than Income Taxes	222	219	644	632
Operating Income	850	890	2,142	2,370
Interest and Investment Income	1	2	10	5
Carrying Costs Income	8	11	20	42
Allowance for Equity Funds Used During Construction	11	19	31	59
Interest Expense	(217)	(221)	(664)	(662)
Income Before Income Tax Expense and Equity Earnings	653	701	1,539	1,814
Income Tax Expense	246	231	561	596
Equity Earnings of Unconsolidated Subsidiaries	2	1	2	2
Net Income	$ 409	$ 471	$ 980	$ 1,220

Summary of KWh Energy Sales for Utility Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in millions of KWhs)			
Retail:				
Residential	16,414	17,664	45,299	45,617
Commercial	13,861	14,091	37,964	38,444
Industrial	14,158	14,729	42,521	44,798
Miscellaneous	797	824	2,252	2,325
Total Retail (a)	45,230	47,308	128,036	131,184
Wholesale	13,960	12,876	34,164	30,409
Total KWhs	59,190	60,184	162,200	161,593

(a) Represents energy delivered to distribution customers.

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Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in degree days)			
Eastern Region				
Actual - Heating (a)	1	9	1,986	1,388
Normal - Heating (b)	7	7	1,887	1,923
Actual - Cooling (c)	655	816	1,007	1,245
Normal - Cooling (b)	705	709	1,015	1,012
Western Region				
Actual - Heating (a)	-	-	606	348
Normal - Heating (b)	1	1	588	602
Actual - Cooling (d)	1,387	1,525	2,254	2,619
Normal - Cooling (b)	1,369	1,367	2,217	2,201

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

Third Quarter of 2013 Compared to Third Quarter of 2012

Reconciliation of Third Quarter of 2012 to Third Quarter of 2013
Net Income from Utility Operations
(in millions)

Third Quarter of 2012	$	471
Changes in Gross Margin:		
Retail Margins		20
Off-system Sales		(22)
Transmission Revenues		29
Other Revenues		(14)
Total Change in Gross Margin		13
Changes in Expenses and Other:		
Other Operation and Maintenance		56
Asset Impairments and Other Related Charges		(131)
Depreciation and Amortization		25
Taxes Other Than Income Taxes		(3)
Interest and Investment Income		(1)
Carrying Costs Income		(3)
Allowance for Equity Funds Used During Construction		(8)
Interest Expense		4
Equity Earnings of Unconsolidated Subsidiaries		1
Total Change in Expenses and Other		(60)
Income Tax Expense		(15)
Third Quarter of 2013	$	409

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 $20 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $63 million rate increase for SWEPCo.
    - A $62 million rate increase for OPCo.
    - A $29 million rate increase for I&M.

      For the rate increases described above, $42 million of these increases relate to riders/trackers which have corresponding increases in expense items below.
    - A $16 million increase due to the deferral of consumables and purchased power as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.

  These increases were partially offset by:
  - A $70 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  -

A $60 million decrease in weather-related usage primarily due to 20% and 9% decreases in cooling degree days in our eastern and western regions, respectively.

- Margins from Off-system Sales decreased $22 million primarily due to lower CRES capacity revenues as a result of Reliability Pricing Model pricing effective August 2012, lower physical sales margins, reduced trading and marketing margins and true-up of prior period PJM expenses. The decrease in CRES capacity revenues is partially offset in expense items below.
- Transmission Revenues increased $29 million primarily due to increased transmission revenues from Ohio customers who have switched to alternative CRES providers and rate increases for customers in the SPP and PJM region. The increase in transmission revenues related to CRES providers offsets a portion of the lost revenues included in Retail Margins above.
- Other Revenues decreased $14 million primarily due to the following:

- An $8 million decrease in revenues related to TCC's issuance of securitization bonds in March 2012, which is partially offset by a decrease in Depreciation and Amortization expense.
- A $7 million decrease in revenues due to resolution of contingencies related to pole attachments in the third quarter of 2013. This decrease in Other Revenues is offset by a decrease in Other Operation and Maintenance expense detailed below.

These decreases were partially offset by:

- A $9 million increase in revenues primarily associated with transformer projects for third parties.

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

- Other Operation and Maintenance expenses decreased $56 million primarily due to the following:
  - A $49 million decrease in administrative and general expenses.
  - A $19 million decrease in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $15 million decrease in storm-related expenses.
  - A $13 million decrease due to resolution of contingencies related to pole attachments in the third quarter of 2013. This decrease in Other Operation and Maintenance expense is partially offset by a decrease in Other Revenues detailed above.

  These decreases were partially offset by:
  - A $21 million increase in transmission services due to increased RTO expense within PJM and SPP. This increase was offset by a corresponding increase in Retail Margins.
  - A $19 million increase in remitted Universal Service Fund (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.
- Asset Impairments and Other Related Charges increased by $131 million primarily due to the following:
  - A $111 million increase due to the third quarter 2013 write-off of AFUDC on the Turk Plant that was included in the Texas capital cost cap. This write-off was in accordance with the PUCT's September 2013 open meeting and October 2013 order.
  - A $33 million increase due to KPCo's third quarter 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with the KPSC's October 2013 order.
- Depreciation and Amortization expenses decreased $25 million primarily due to the following:
  - A $34 million decrease as a result of depreciation ceasing on certain Ohio generating plants that were impaired in November 2012 and June 2013.
  - A $9 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of the capacity deferral mechanism.

  These decreases were partially offset by:
  - An $8 million increase due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life approved by the IURC effective March 2013. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
  -

A $7 million increase due to the Turk Plant being placed in service in December 2012.

- Overall higher depreciable property balances.

- Allowance for Equity Funds Used During Construction decreased $8 million primarily due to completed construction of the Turk Plant in December 2012.
- Income Tax Expense increased $15 million primarily due to other book/tax differences which are accounted for on a flow-through basis, partially offset by a decrease in pretax book income.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Reconciliation of Nine Months Ended September 30, 2012 to Nine Months Ended September 30, 2013
Net Income from Utility Operations
(in millions)

Nine Months Ended September 30, 2012	$	1,220
Changes in Gross Margin:		
Retail Margins		147
Off-system Sales		(98)
Transmission Revenues		64
Other Revenues		10
Total Change in Gross Margin		123
Changes in Expenses and Other:		
Other Operation and Maintenance		(104)
Asset Impairments and Other Related Charges		(285)
Depreciation and Amortization		50
Taxes Other Than Income Taxes		(12)
Interest and Investment Income		5
Carrying Costs Income		(22)
Allowance for Equity Funds Used During Construction		(28)
Interest Expense		(2)
Total Change in Expenses and Other		(398)
Income Tax Expense		35
Nine Months Ended September 30, 2013	$	980

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 $147 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $208 million rate increase for OPCo.
    - A $109 million rate increase for SWEPCo.
    - An $80 million rate increase for I&M.
    - A $14 million rate increase for APCo.

      For the rate increases described above, $142 million of these increases relate to riders/trackers which have corresponding increases in expense items below.
  - A $64 million increase due to the deferral of consumables and purchased power as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.

  These increases were partially offset by:
  - A $223 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  -

A $35 million decrease due to OPCo's second quarter 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.

- A $26 million increase in other variable electric generation expenses.
- A $10 million net decrease in weather-related usage primarily due to decreases of 19% and 14% in cooling degree days in our eastern and western regions, respectively, partially offset by increases in heating degree days of 43% and 74% in our eastern and western regions, respectively.

- Margins from Off-system Sales decreased $98 million primarily due to lower CRES capacity revenues as a result of Reliability Pricing Model pricing effective August 2012, lower PJM capacity revenues, reduced trading and marketing margins and true-up of prior period PJM expenses. The decrease in CRES capacity revenues is partially offset in expense items below.
- Transmission Revenues increased $64 million primarily due to increased transmission revenues from Ohio customers who have switched to alternative CRES providers and rate increases for customers in the SPP region. The increase in transmission revenues related to CRES providers offsets a portion of the lost revenues included in Retail Margins above.

- Other Revenues increased $10 million primarily due to the following:
  - A $15 million increase in revenues primarily associated with transformer projects for third parties.

  This increase was partially offset by:
  - A $7 million decrease in revenues due to resolution of contingencies related to pole attachments in the third quarter of 2013. This decrease in Other Revenues is offset by a decrease in Other Operation and Maintenance expense.

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

- Other Operation and Maintenance expenses increased $104 million primarily due to the following:
  - A $64 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.
  - A $49 million increase in plant outages during 2013.
  - A $30 million write-off in the first quarter of 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - 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 $28 million decrease due to the deferral of capacity-related costs as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.
  - A $25 million decrease due to an agreement reached to settle an insurance claim in the first quarter of 2013.
- Asset Impairments and Other Related Charges increased $285 million primarily due to the following:
  - A $154 million increase due to the second quarter 2013 impairment of Muskingum River Plant, Unit 5.
  - A $111 million increase due to the third quarter 2013 write-off of AFUDC on the Turk Plant that was included in the Texas capital cost cap. This write-off was in accordance with the PUCT's September 2013 open meeting and October 2013 order.
  - A $33 million increase due to KPCo's third quarter 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with the KPSC's October 2013 order.
- Depreciation and Amortization expenses decreased $50 million primarily due to the following:
  - A $92 million decrease as a result of depreciation ceasing on certain Ohio generating plants that were impaired in November 2012 and June 2013.
  - A $44 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.

  These decreases were partially offset by:
  - A $29 million increase due to the Turk Plant being placed in service in December 2012.
  - A $23 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.

- Taxes Other Than Income Taxes increased $12 million primarily due to increased property taxes as a result of increased capital investments.
- Carrying Costs Income decreased $22 million primarily due to the following:
  - An $11 million decrease due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in January 2012 and decreased carrying charges related to the Dresden Plant.
  - An $8 million decrease in carrying costs income due to the first quarter 2012 recording of debt carrying costs prior to TCC's issuance of securitization bonds in March 2012.
- Allowance for Equity Funds Used During Construction decreased $28 million primarily due to completed construction of the Turk Plant in December 2012.
- Income Tax Expense decreased $35 million primarily due to a decrease in pretax book income partially offset by audit settlements for previous years recorded in 2012 and other book/tax differences which are accounted for on a flow-through basis.

TRANSMISSION OPERATIONS

Third Quarter of 2013 Compared to Third Quarter of 2012

Net Income from our Transmission Operations segment increased from $14 million in 2012 to $22 million in 2013 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Net Income from our Transmission Operations segment increased from $31 million in 2012 to $53 million in 2013 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

AEP RIVER OPERATIONS

Third Quarter of 2013 Compared to Third Quarter of 2012

Net Income from our AEP River Operations segment was unchanged in comparison to 2012.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Net Income from our AEP River Operations segment decreased from income of $11 million in 2012 to a loss of $12 million in 2013 due to unfavorable operating conditions caused by extremely low water levels in the first quarter of 2013 followed by flood conditions later in the spring. In addition, we have experienced significant reductions in grain and export coal demand.

GENERATION AND MARKETING

Third Quarter of 2013 Compared to Third Quarter of 2012

Net Income from our Generation and Marketing segment decreased from $10 million in 2012 to $4 million in 2013 primarily due to decreased retail margins and reduced inception gains from marketing activities, partially offset by favorable gross margins at the Oklaunion Plant.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Net Income from our Generation and Marketing segment increased from $4 million in 2012 to $15 million in 2013 primarily due to higher trading and marketing margins and increased retail activity resulting from our March 2012 acquisition of BlueStar.

ALL OTHER

Third Quarter of 2013 Compared to Third Quarter of 2012

Net Income from All Other increased from a loss of $6 million in 2012 to $0 in 2013 primarily due to a reduction in interest expense due to lower interest rates.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Net Income from All Other increased from a loss of $25 million in 2012 to income of $101 million in 2013 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

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AEP SYSTEM INCOME TAXES

Third Quarter of 2013 Compared to Third Quarter of 2012

Income Tax Expense increased $16 million primarily due to other book/tax differences which are accounted for on a flow through basis and the regulatory accounting treatment of state income taxes, partially offset by a decrease in pretax book income.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Income Tax Expense decreased $100 million primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013, a decrease in pretax book income, partially offset by audit settlements for previous years recorded in 2012 and other book/tax differences which are accounted for on a flow through basis.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2013			December 31, 2012		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$	17,568	50.9 %	$	17,757	52.3 %
Short-term Debt		1,218	3.5		981	2.9
Total Debt		18,786	54.4		18,738	55.2
AEP Common Equity		15,762	45.6		15,237	44.8
Noncontrolling Interests		1	-		-	-
Total Debt and Equity Capitalization	$	34,549	100.0 %	$	33,975	100.0 %

Our ratio of debt-to-total capital declined from 55.2% as of December 31, 2012 to 54.4% as of September 30, 2013 primarily due to an increase in our common equity from earnings.

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 September 30, 2013, we had $4.5 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-and-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of September 30, 2013, our available liquidity was approximately $3.3 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
	Revolving Credit Facility	$ 1,750	June 2016
	Revolving Credit Facility	1,750	July 2017
Term Credit Facility		1,000	May 2015
Total		4,500	
Cash and Cash Equivalents		147	
Total Liquidity Sources		4,647	
Less:	AEP Commercial Paper Outstanding	518	
	Letters of Credit Issued	185	
	Draw on Term Credit Facility	600	
Net Available Liquidity		$ 3,344	

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 the first nine months of 2013 was $904 million. The weighted-average interest rate for our commercial paper during 2013 was 0.32%.

In February 2013, we entered into a $1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate the corporate separation of generation assets from transmission and distribution. In July 2013, we terminated the $1 billion term credit facility. In July 2013, AEPGenCo, 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 the corporate separation of generation assets from transmission and distribution.

Securitized Accounts Receivable

In June 2013, we amended our receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. We amended a commitment of $385 million to expire in June 2014. The remaining commitment of $315 million expires in June 2015.

West Virginia Securitization of Regulatory Assets

In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered Expanded Net Energy Charge (ENEC) deferral balance, other ENEC-related assets and related financing costs. In March 2013, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC, which recommended the WVPSC authorize APCo to securitize $376 million plus upfront financing costs. In September 2013, the WVPSC approved the settlement agreement. The securitization bonds are expected to be issued in the fourth quarter of 2013.

Ohio Securitization of Regulatory Assets

In March 2013, the PUCO approved OPCo's request to securitize the Deferred Asset Recovery Rider (DARR) balance. The DARR was originally scheduled to be recovered through 2018 by a non-bypassable rider. In August 2013, OPCo issued $267 million of Securitization Bonds 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 transition assets over a period not to exceed eight years.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our revolving credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of September 30, 2013, this contractually-defined percentage was 50.9%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of September 30, 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 and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

The term credit facility may be drawn upon until February 2014. Repayments prior to maturity are permitted. However, any amount that is repaid may not be re-borrowed and is a permanent reduction of the facility.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of September 30, 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 October 2013. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

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

Credit Ratings

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

CASH FLOW

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

	Nine Months Ended September 30, 2013	2012
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 279	$ 221
Net Cash Flows from Operating Activities	3,040	2,912
Net Cash Flows Used for Investing Activities	(2,520)	(2,281)
Net Cash Flows Used for Financing Activities	(652)	(409)
Net Increase (Decrease) in Cash and Cash Equivalents	(132)	222
Cash and Cash Equivalents at End of Period	$ 147	$ 443

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

Operating Activities

	Nine Months Ended September 30, 2013	2012
	(in millions)	
Net Income	$ 1,137	$ 1,241
Depreciation and Amortization	1,310	1,353
Other	593	318
Net Cash Flows from Operating Activities	$ 3,040	$ 2,912

Net Cash Flows from Operating Activities were $3 billion in 2013 consisting primarily of Net Income of $1.1 billion and $1.3 billion of noncash Depreciation and Amortization. Included in Other were $298 million of Asset Impairments related to Muskingum River Plant, Unit 5, Turk and Big Sandy Plants, partially offset by $157 million of Ohio capacity deferrals as a result of the PUCO's July 2012 approval of a capacity deferral mechanism. 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/book temporary differences from operations. Net cash flows for Accrued Taxes were a result of recording the estimated federal tax loss associated with tax/book temporary differences and the recognition of the tax benefit related to the U.K. Windfall Tax.

Net Cash Flows from Operating Activities were $2.9 billion in 2012 consisting primarily of Net Income of $1.2 billion and $1.4 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. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Cash was used to pay real and personal property taxes and to reduce accounts payable. 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. We also contributed $100 million to our qualified pension trust.

Investing Activities

	Nine Months Ended September 30, 2013	2012
	(in millions)	
Construction Expenditures	$ (2,481)	$ (2,108)
Acquisitions of Nuclear Fuel	(110)	(13)
Acquisitions of Assets/Businesses	(6)	(89)
Insurance Proceeds Related to Cook Plant Fire	72	-
Proceeds from Sales of Assets	14	13
Other	(9)	(84)
Net Cash Flows Used for Investing Activities	$ (2,520)	$ (2,281)

Net Cash Flows Used for Investing Activities were $2.5 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were $2.3 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.

Financing Activities

	Nine Months Ended September 30, 2013	2012
	(in millions)	
Issuance of Common Stock, Net	$ 61	$ 64
Issuance of Debt, Net	43	262
Dividends Paid on Common Stock	(709)	(687)
Other	(47)	(48)
Net Cash Flows Used for Financing Activities	$ (652)	$ (409)

Net Cash Flows Used for Financing Activities were $652 million in 2013. Our net debt issuances were $43 million. The net issuances included issuances of $475 million of senior unsecured notes, $800 million draws on a $1 billion term credit facility, $305 million of pollution control bonds, $267 million of securitization bonds, $251 million of notes payable and other debt and an increase in short-term borrowing of $237 million offset by retirements of $1.8 billion of senior unsecured and other debt notes, $211 million of securitization bonds and $281 million of pollution control bonds. We paid common stock dividends of $709 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Financing Activities were $409 million in 2012. Our net debt issuances were $262 million. The net issuances included issuances of $800 million of securitization bonds, $550 million of senior unsecured notes, $197 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $513 million of senior unsecured and other debt notes, $220 million of pollution control bonds, $171 million of securitization bonds and a decrease in short-term borrowing of $434 million. We paid common stock dividends of $687 million.

In October 2013, I&M retired $37 million of Notes Payable related to DCC Fuel.

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BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.6 billion of construction expenditures excluding equity AFUDC and capitalized interest for 2013. The total budgeted construction expenditures for 2013 remain unchanged but the table below shows updates to the allocation of expenditures as of September 30, 2013. For 2014 and 2015, we forecast construction expenditures of $3.8 billion each year. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2013 updated estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2013 Budgeted Construction Expenditures (in millions)	
Environmental	$	437
Generation		585
Transmission		1,455
Distribution		999
Other		121
Total	$	3,597

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:

	September 30, 2013		December 31, 2012	
	(in millions)			
Rockport Plant, Unit 2 Future Minimum Lease Payments	$	1,404	$	1,478
Railcars Maximum Potential Loss from Lease Agreement		19		25

For complete information on each of these off-balance sheet arrangements, see the "Off-balance Sheet Arrangements" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2012 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2012 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

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 future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk as we occasionally procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations, 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)
Nine Months Ended September 30, 2013

	Utility Operations	Generation and Marketing (in millions)	Total
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 68	$ 128	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(23)	(16)	(39)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-	12	12
Changes in Fair Value Due to Market Fluctuations During the Period (b)	1	15	16
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	6	-	6
Total MTM Risk Management Contract Net Assets as of September 30, 2013	$ 52	$ 139	191
Commodity Cash Flow Hedge Contracts			(2)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(2)
Fair Value Hedge Contracts			(7)
Collateral Deposits			21
Total MTM Derivative Contract Net Assets as of September 30, 2013			$ 201

(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 condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing 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 September 30, 2013, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.3%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of September 30, 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	$ 634	$ -	$ 634	2	$ 297
Split Rating	1	1	-	-	-
Noninvestment Grade	-	-	-	1	-
No External Ratings:					
Internal Investment Grade	75	-	75	3	35
Internal Noninvestment Grade	74	10	64	2	40
Total as of September 30, 2013	$ 784	$ 11	$ 773	8	$ 372
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338

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 September 30, 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

Nine Months Ended September 30, 2013				Twelve Months Ended 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 four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of September 30, 2013 and December 31, 2012, the estimated EaR on our debt portfolio for the following twelve months was $35 million and $42 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2013 and 2012
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
REVENUES				
Utility Operations	$ 3,797	$ 3,814	$ 10,539	$ 10,412
Other Revenues	379	342	1,045	920
TOTAL REVENUES	4,176	4,156	11,584	11,332
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,168	1,180	3,107	3,137
Purchased Electricity for Resale	373	327	1,103	855
Other Operation	677	775	2,079	2,150
Maintenance	261	255	839	769
Asset Impairments and Other Related Charges	144	13	298	13
Depreciation and Amortization	447	470	1,310	1,353
Taxes Other Than Income Taxes	231	224	671	648
TOTAL EXPENSES	3,301	3,244	9,407	8,925
OPERATING INCOME	875	912	2,177	2,407
Other Income (Expense):				
Interest and Investment Income	3	2	55	6
Carrying Costs Income	8	11	20	42
Allowance for Equity Funds Used During Construction	19	23	51	70
Interest Expense	(225)	(233)	(685)	(697)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	680	715	1,618	1,828
Income Tax Expense	257	241	520	620
Equity Earnings of Unconsolidated Subsidiaries	11	14	39	33
NET INCOME	434	488	1,137	1,241
Net Income Attributable to Noncontrolling Interests	1	1	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 433	$ 487	$ 1,134	$ 1,238

WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING		486,932,747		484,979,543		486,353,876		484,437,875
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	0.89	$	1.00	$	2.33	$	2.55
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING		487,258,905		485,362,858		486,792,914		484,826,123
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$	0.89	$	1.00	$	2.33	$	2.55
CASH DIVIDENDS DECLARED PER SHARE	$	0.49	$	0.47	$	1.45	$	1.41

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 39.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2013 and 2012
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net Income	$ 434	$ 488	$ 1,137	$ 1,241
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $1 and $7 for the Three Months Ended September 30, 2013 and 2012, Respectively, and $7 and $4 for the Nine Months Ended September 30, 2013 and 2012, Respectively	(1)	13	13	(8)
Securities Available for Sale, Net of Tax of $- and $- for the Three Months Ended September 30, 2013 and 2012, Respectively, and $1 and $1 for the Nine Months Ended September 30, 2013 and 2012, Respectively	1	1	2	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $4 and $4 for the Three Months Ended September 30, 2013 and 2012, Respectively, and $9 and $12 for the Nine Months Ended September 30, 2013 and 2012, Respectively	7	7	16	22
TOTAL OTHER COMPREHENSIVE INCOME	7	21	31	16
TOTAL COMPREHENSIVE INCOME	441	509	1,168	1,257
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 440	$ 508	$ 1,165	$ 1,254

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 39.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2013 and 2012
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665
Issuance of Common Stock	2	12	52				64
Common Stock Dividends				(684)		(3)	(687)
Other Changes in Equity			8			(1)	7
Net Income				1,238		3	1,241
Other Comprehensive Income					16		16
TOTAL EQUITY – SEPTEMBER 30, 2012	506	$ 3,286	$ 6,030	$ 6,444	$ (454)	$ -	$ 15,306
TOTAL EQUITY – DECEMBER 31, 2012	506	$ 3,289	$ 6,049	$ 6,236	$ (337)	$ -	$ 15,237
Issuance of Common Stock	2	10	51				61
Common Stock Dividends				(706)		(3)	(709)
Other Changes in Equity			5			1	6
Net Income				1,134		3	1,137
Other Comprehensive Income					31		31
TOTAL EQUITY – SEPTEMBER 30, 2013	508	$ 3,299	$ 6,105	$ 6,664	$ (306)	$ 1	$ 15,763

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 39.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2013 and December 31, 2012
(in millions)
(Unaudited)

	September 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 147	$ 279
Other Temporary Investments (September 30, 2013 and December 31, 2012 Amounts Include $275 and $311, Respectively, Related to Transition Funding, Phase-in-Recovery Funding and EIS)	288	324
Accounts Receivable:		
Customers	657	685
Accrued Unbilled Revenues	164	195
Pledged Accounts Receivable – AEP Credit	982	856
Miscellaneous	107	171
Allowance for Uncollectible Accounts	(54)	(36)
Total Accounts Receivable	1,856	1,871
Fuel	748	844
Materials and Supplies	692	675
Risk Management Assets	171	191
Regulatory Asset for Under-Recovered Fuel Costs	81	88
Margin Deposits	72	76
Prepayments and Other Current Assets	262	241
TOTAL CURRENT ASSETS	4,317	4,589
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,172	26,279
Transmission	10,256	9,846
Distribution	16,067	15,565
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	4,060	3,945
Construction Work in Progress	2,489	1,819
Total Property, Plant and Equipment	59,044	57,454
Accumulated Depreciation and Amortization	19,174	18,691
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	39,870	38,763
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,038	5,106
Securitized Transition Assets	2,080	2,117
Spent Nuclear Fuel and Decommissioning Trusts	1,839	1,706
Goodwill	91	91
Long-term Risk Management Assets	314	368
Deferred Charges and Other Noncurrent Assets	1,414	1,627

TOTAL OTHER NONCURRENT ASSETS		10,776		11,015
TOTAL ASSETS	$	54,963	$	54,367

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 39.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2013 and December 31, 2012
(dollars in millions)
(Unaudited)

	September 30, 2013	December 31, 2012
CURRENT LIABILITIES		
Accounts Payable	$ 1,044	$ 1,169
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	700	657
Other Short-term Debt	518	324
Total Short-term Debt	1,218	981
Long-term Debt Due Within One Year (September 30, 2013 and December 31, 2012 Amounts Include $433 and $367, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding and Sabine)	1,366	2,171
Risk Management Liabilities	102	155
Customer Deposits	298	316
Accrued Taxes	590	747
Accrued Interest	219	269
Regulatory Liability for Over-Recovered Fuel Costs	14	47
Other Current Liabilities	841	968
TOTAL CURRENT LIABILITIES	5,692	6,823
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2013 and December 31, 2012 Amounts Include $2,222 and $2,227, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding and Sabine)	16,202	15,586
Long-term Risk Management Liabilities	182	214
Deferred Income Taxes	9,871	9,252
Regulatory Liabilities and Deferred Investment Tax Credits	3,640	3,544
Asset Retirement Obligations	1,736	1,696
Employee Benefits and Pension Obligations	986	1,075
Deferred Credits and Other Noncurrent Liabilities	891	940
TOTAL NONCURRENT LIABILITIES	33,508	32,307
TOTAL LIABILITIES	39,200	39,130
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2013	2012
Shares Authorized	600,000,000	600,000,000
Shares Issued	507,594,430	506,004,962

(20,336,592 Shares were Held in Treasury as of September 30, 2013 and December 31, 2012)		3,299		3,289
Paid-in Capital		6,105		6,049
Retained Earnings		6,664		6,236
Accumulated Other Comprehensive Income (Loss)		(306)		(337)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		15,762		15,237
Noncontrolling Interests		1		-
TOTAL EQUITY		15,763		15,237
TOTAL LIABILITIES AND EQUITY	$	54,963	$	54,367

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 39.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2013 and 2012
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2013	2012
OPERATING ACTIVITIES		
Net Income	$ 1,137	$ 1,241
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,310	1,353
Deferred Income Taxes	582	592
Asset Impairments and Other Related Charges	298	13
Carrying Costs Income	(20)	(42)
Allowance for Equity Funds Used During Construction	(51)	(70)
Mark-to-Market of Risk Management Contracts	29	70
Amortization of Nuclear Fuel	101	100
Pension Contributions to Qualified Plan Trust	-	(100)
Property Taxes	191	181
Fuel Over/Under-Recovery, Net	38	133
Deferral of Ohio Capacity Costs, Net	(157)	(22)
Change in Other Noncurrent Assets	(35)	(173)
Change in Other Noncurrent Liabilities	16	119
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	4	(4)
Fuel, Materials and Supplies	72	(169)
Accounts Payable	(28)	(135)
Accrued Taxes, Net	(278)	(130)
Other Current Assets	(5)	(28)
Other Current Liabilities	(164)	(17)
Net Cash Flows from Operating Activities	3,040	2,912
INVESTING ACTIVITIES		
Construction Expenditures	(2,481)	(2,108)
Change in Other Temporary Investments, Net	53	19
Purchases of Investment Securities	(693)	(745)
Sales of Investment Securities	635	699
Acquisitions of Nuclear Fuel	(110)	(13)
Acquisitions of Assets/Businesses	(6)	(89)
Insurance Proceeds Related to Cook Plant Fire	72	-
Proceeds from Sales of Assets	14	13
Other Investing Activities	(4)	(57)
Net Cash Flows Used for Investing Activities	(2,520)	(2,281)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	61	64

Issuance of Long-term Debt		2,087		1,600
Commercial Paper and Credit Facility Borrowings		17		21
Change in Short-term Debt, Net		240		(417)
Retirement of Long-term Debt		(2,281)		(904)
Commercial Paper and Credit Facility Repayments		(20)		(38)
Principal Payments for Capital Lease Obligations		(53)		(53)
Dividends Paid on Common Stock		(709)		(687)
Other Financing Activities		6		5
Net Cash Flows Used for Financing Activities		(652)		(409)
Net Increase (Decrease) in Cash and Cash Equivalents		(132)		222
Cash and Cash Equivalents at Beginning of Period		279		221
Cash and Cash Equivalents at End of Period	$	147	$	443
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	702	$	698
Net Cash Paid (Received) for Income Taxes		(64)		(44)
Noncash Acquisitions Under Capital Leases		53		46
Construction Expenditures Included in Current Liabilities as of September 30,		363		325
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,		-		43
Noncash Assumption of Liabilities Related to Acquisitions		-		56

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 39.

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

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1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2013 is not necessarily indicative of results that may be expected for the year ending December 31, 2013. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2012 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 26, 2013.

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following tables present our basic and diluted EPS calculations included on our condensed statements of income:

	Three Months Ended September 30,			
	2013		2012	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 433		$ 487	
Weighted Average Number of Basic Shares Outstanding	486.9	$ 0.89	485.0	$ 1.00
Weighted Average Dilutive Effect of:				
Stock Options	-	-	0.1	-
Restricted Stock Units	0.4	-	0.3	-
Weighted Average Number of Diluted Shares Outstanding	487.3	$ 0.89	485.4	$ 1.00

	Nine Months Ended September 30,			
	2013		2012	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,134		$ 1,238	
	486.4	$ 2.33	484.4	$ 2.55

Weighted Average Number of Basic Shares Outstanding						
Weighted Average Dilutive Effect of:						
Stock Options	-		-	0.1		-
Restricted Stock Units	0.4		-	0.3		-
Weighted Average Number of Diluted Shares Outstanding	486.8	$	2.33	484.8	$	2.55

There were no antidilutive shares outstanding as of September 30, 2013 and 2012.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
			(in millions)		
Balance in AOCI as of June 30, 2013	$ 1	$ (25)	$ 5	$ (294)	$ (313)
Change in Fair Value Recognized in AOCI	1	-	1	-	2
Amounts Reclassified from AOCI	(3)	1	-	7	5
Net Current Period Other Comprehensive Income	(2)	1	1	7	7
Balance in AOCI as of September 30, 2013	$ (1)	$ (24)	$ 6	$ (287)	$ (306)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
			(in millions)		
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ 4	$ (303)	$ (337)
Change in Fair Value Recognized in AOCI	11	2	2	-	15
Amounts Reclassified from AOCI	(4)	4	-	16	16
Net Current Period Other Comprehensive Income	7	6	2	16	31
Balance in AOCI as of September 30, 2013	$ (1)	$ (24)	$ 6	$ (287)	$ (306)

Reclassifications Out of Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2013

Gains and Losses on Cash Flow Hedges		Amount of (Gain) Loss Reclassified from AOCI (in millions)
Commodity:		
Utility Operations Revenues	$	(1)
Other Revenues		(3)
Purchased Electricity for Resale		(1)
Property, Plant and Equipment		-
Regulatory Assets/(Liabilities), Net (a)		-
Subtotal - Commodity		(5)
Interest Rate and Foreign Currency:		
Interest Expense		2
Subtotal - Interest Rate and Foreign Currency		2
Reclassifications from AOCI, before Income Tax (Expense) Credit		(3)
Income Tax (Expense) Credit		(1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		(2)
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		-
Amortization of Pension and OPEB		
Prior Service Cost (Credit)		(7)
Actuarial (Gains)/Losses		18
Reclassifications from AOCI, before Income Tax (Expense) Credit		11
Income Tax (Expense) Credit		4
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		7
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$	5

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2013

Gains and Losses on Cash Flow Hedges		Amount of (Gain) Loss Reclassified from AOCI (in millions)
Commodity:		
Utility Operations Revenues	$	(1)
Other Revenues		(8)
Purchased Electricity for Resale		3
Property, Plant and Equipment		-
Regulatory Assets/(Liabilities), Net (a)		-
Subtotal - Commodity		(6)
Interest Rate and Foreign Currency:		
Interest Expense		6
Subtotal - Interest Rate and Foreign Currency		6
Reclassifications from AOCI, before Income Tax (Expense) Credit		-
Income Tax (Expense) Credit		-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		-
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		-
Amortization of Pension and OPEB		
Prior Service Cost (Credit)		(16)
Actuarial (Gains)/Losses		41
Reclassifications from AOCI, before Income Tax (Expense) Credit		25
Income Tax (Expense) Credit		9
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		16
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$	16

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

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2012. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of June 30, 2012	$ (14)	$ (30)	$ (44)
Changes in Fair Value Recognized in AOCI	16	(3)	13
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(1)	-	(1)
Purchased Electricity for Resale	-	-	-
Interest Expense	-	1	1
Regulatory Assets (a)	-	-	-
Balance in AOCI as of September 30, 2012	$ 1	$ (32)	$ (31)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 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	(7)	(15)	(22)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(4)	-	(4)
Purchased Electricity for Resale	13	-	13
Interest Expense	-	3	3
Regulatory Assets (a)	2	-	2
Balance in AOCI as of September 30, 2012	$ 1	$ (32)	$ (31)

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

The following tables provide details of changes in unrealized gains and losses related to Securities Available for Sale and the reasons for changes for the three and nine months ended September 30, 2012. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Securities Available for Sale
For the Three Months Ended September 30, 2012

		(in millions)
Balance in AOCI as of June 30, 2012	$	3
Changes in Fair Value Recognized in AOCI		1
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:		
Interest Income		-
Balance in AOCI as of September 30, 2012	$	4

Total Accumulated Other Comprehensive Income (Loss) Activity for Securities Available for Sale
For the Nine Months Ended September 30, 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 September 30, 2012	$	4

3. RATE MATTERS

As discussed in the 2012 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2012 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2013 and updates the 2012 Annual Report.

Regulatory Assets Not Yet Being Recovered

		September 30, 2013		December 31, 2012
		(in millions)		
Noncurrent Regulatory Assets				
Regulatory assets not yet being recovered pending future proceedings:				
Regulatory Assets Currently Earning a Return				
Storm Related Costs	$	22	$	23
Economic Development Rider		14		13
Other Regulatory Assets Not Yet Being Recovered		3		1
Regulatory Assets Currently Not Earning a Return				
Storm Related Costs		153		172
Ormet Special Rate Recovery Mechanism		32		5
Virginia Environmental Rate Adjustment Clause		28		29

Expanded Net Energy Charge - Coal Inventory		21		-
Under-Recovered Capacity Costs		16		-
Mountaineer Carbon Capture and Storage Product Validation Facility		14		14
Litigation Settlement		-		11
Other Regulatory Assets Not Yet Being Recovered		38		36
Total Regulatory Assets Not Yet Being Recovered	$	341	$	304

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

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

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of September 30, 2013, OPCo's net deferred fuel balance was $467 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project by the end of 2013. In September 2013, a proposed second phase of OPCo's gridSMART program was filed with the PUCO which included a recommended technology solution project to satisfy this PUCO directive.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. In October 2013, the PUCO issued an order on the 2010 SEET filing. As a result, the PUCO ordered a $7 million refund of pretax earnings to customers. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's requests to file the SEET for 2011 and 2012 one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 for OPCo. Additionally, management does not currently believe that there will be significantly excessive earnings in 2013 for OPCo.

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. The IEU and the Ohio Consumers' Counsel also filed appeals, regarding the PUCO decision in the PIRR proceeding, at the Supreme Court of Ohio in November 2012 arguing principally 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 intervenor appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of September 30, 2013, could reduce carrying costs by $33 million including $17 million of unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

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, which was generally upheld in rehearing orders in January and March 2013.

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

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $33/MW day through May 2014. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio. As of September 30, 2013, OPCo's incurred deferred capacity costs balance of $228 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

As part of the August 2012 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs.

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 June 2013, intervenors in the CBP docket filed recommendations that include prospective rate reductions for capacity and non-energy FAC issues. OPCo maintains that the August 2012 ESP order fixed OPCo's non-energy generation rates through December 31, 2014 and ordered the application of a $188.88/MW day price for capacity for non-shopping customers effective January 1, 2015. However, intervenors maintained that OPCo's non-energy generation rates should be reduced prior to January 1, 2015 to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned (10% prior to June 2014 and 60% for the period June 1, 2014 through December 31, 2014). An additional proposal to prospectively offset deferred capacity costs based upon the results of the energy-only auctions was not quantified and OPCo maintains that proposal should not be adopted in light of prior PUCO orders. Hearings related to the CBP were held at the PUCO in June and July 2013. A decision from the PUCO is pending.

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.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In 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 October 2013, OPCo filed an application with the PUCO to amend the corporate separation plan by permitting OPCo to retain certain rights to purchase power from OVEC.

Also in October 2012, filings at the FERC were submitted related to corporate separation. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AEPGenCo. Results of operations related to generation in Ohio will be largely determined by prevailing market conditions effective January 1, 2014. 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. OPCo also requested approval of a weighted average cost of capital carrying charge if recovery of these costs did not begin prior to April 2013. In May 2013, intervenors filed comments with various recommendations including reductions in the amount of storm costs recoverable up to the amount deferred, an extended recovery period, and an additional review of the storm costs including the allocation of costs to capital. Hearings at the PUCO are scheduled for December 2013. As of September 30, 2013, OPCo recorded $61 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

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation 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 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 are scheduled for 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, has a contract through 2018 to purchase power from OPCo. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware. In October 2013, following applications to the PUCO to amend Ormet's power contract with OPCo, Ormet announced that they are unable to emerge from bankruptcy and are shutting down operations effective immediately. Based upon previous PUCO rulings to provide 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. As of September 30, 2013, OPCo has recorded a regulatory asset of $32 million of Ormet amounts collectible through the Economic Development Rider as a result of these special rate recovery mechanisms and amounts unpaid by Ormet.

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 the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts referenced 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 September 30, 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 OPCo refund all collected pre-construction costs to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings 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 September 30, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.8 billion, including AFUDC and capitalized interest of $328 million and related transmission costs of $118 million. As of September 30, 2013, a provision of $173 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total capitalized expenditures of $1.6 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. The Arkansas portion of the Turk Plant output 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. See the "2012 Texas Base Rate Case" disclosure below for a discussion of a PUCT order on the Texas capital cost cap. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In March 2013, SWEPCo and the TIEC's petitions for review at the Supreme Court of Texas were denied and in August 2013, SWEPCo and the TIEC's motions for rehearing at the Supreme Court of Texas were denied.

If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Turk Plant, transmission lines or Welsh Plant, Unit 2, 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, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operation and maintenance costs.

In September 2012, an Administrative Law Judge (ALJ) issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In May 2013, the ALJ issued a proposal for decision recommending a rate increase but found SWEPCo imprudent for failing to cancel the Turk Plant in 2010.

The PUCT rejected the ALJ's imprudence recommendation, but during a September 2013 open meeting, the PUCT stated that it would limit the recovery of the investment in the Turk Plant by imposing a Texas jurisdictional cost cap established in the recently concluded Certificate of Convenience and Necessity (CCN) case appeal discussed above (the Texas capital cost cap). The PUCT also provided new details on how the cost cap would be applied. In October 2013, the PUCT issued an order with the determination that the Turk Plant 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 impairment of $111 million in Asset Impairments and Other Related Charges on the statement of income. The order approved an annual rate increase of approximately $39 million based upon a return on common equity of 9.65%. As a result of this approval, SWEPCo retroactively applied these rates back to the end of January 2013. The approval also provided for the following: (a) no disallowances to the existing book investment in the Stall Plant, and (b) the exclusion, until SWEPCo files and obtains approval of a Transmission Cost Recovery Rider, of the Turk Plant transmission line investment that was not in service at the end of the test year. Additionally, the PUCT determined that it would defer 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 September 30, 2013, the net book value of Welsh Plant, Unit 2 was $94 million, before cost of removal, including materials and supplies inventory and CWIP. Requests for rehearing may be filed within 30 days of receipt of the PUCT order. SWEPCo intends to file a motion for rehearing with the PUCT in late October 2013.

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

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 prudence 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 prudence 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 presently owned by OPCo. In June 2013, intervenors filed testimony with the WVPSC and made recommendations relating to APCo's proposed asset transfers including the transfer of only one plant and the issuance of a Request for Proposals for any additional capacity and energy requirements. Also in June 2013, the WVPSC staff filed testimony recommending the approval of the proposed asset transfers, with rate recognition to occur in a future base rate case, but limiting the liabilities to be transferred to the types and amounts reflected in the net book value of the assets. In July 2013, the Virginia SCC approved the transfer of OPCo's 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 disallowance is approximately $39 million. The Virginia SCC also denied the proposed transfer of OPCo's one-half interest in the Mitchell Plant to APCo. APCo plans to pursue cost recovery of the transferred interest in the Amos Plant in Virginia in the 2014 biennial filing. Management is currently evaluating the implications of this order while awaiting a final decision from the WVPSC. Hearings were held at the WVPSC in July 2013. In September 2013, a WVPSC staff brief advocated for the approval of the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo at the reduced value, for rate purposes, as approved by the Virginia SCC which could result in an additional $44 million disallowance related to the West Virginia and FERC jurisdictional shares of Amos Plant, Unit 3 and the denial of the proposed transfer of OPCo's one-half interest in the Mitchell Plant to APCo. This matter is currently pending before the WVPSC. Any disallowance related to recovery of Amos Plant, Unit 3, as a result of Virginia SCC or WVPSC orders, would be recorded upon the transfer, expected in the fourth quarter of 2013. If APCo and WPCo are not ultimately permitted to recover their incurred costs, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of September 30, 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 effective February 2014 over a one-year period. In March 2013, the environmental RAC surcharge expired related to the collection of 2009 and 2010 environmental compliance costs. In August 2013, a settlement agreement was submitted to the Virginia SCC which recommended approval of an environmental RAC to recover $38 million of the 2012 and 2011 environmental compliance costs. In September 2013, the Hearing Examiner recommended the approval of the settlement agreement. An order is expected from the Virginia SCC no later than November 2013. APCo has deferred $28 million as of September 30, 2013 for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding $10 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the environmental RAC, it could reduce future net income and cash flows.

2013 Virginia Generation Rate Adjustment Clause (Generation RAC) Filing

In March 2013, APCo filed with the Virginia SCC for an increase in its generation RAC revenues of $12 million for a total of $38 million annually to collect costs related to the Dresden Plant. In August 2013, a settlement agreement was submitted to the Virginia SCC which recommended approval of an increase in the generation RAC to $37 million annually if the proposed merger of WPCo into APCo occurs by January 1, 2014 or an increase to $39 million if the proposed merger does not occur by January 1, 2014. Per the settlement agreement, the generation RAC increase is to be effective no later than March 2014 for a period of one year at which time the component to collect an under-recovery of approximately $9 million will cease and the remaining component to recover on-going Dresden Plant costs will continue. In October 2013, the Hearing Examiner recommended the approval of the settlement agreement. An order is expected from the Virginia SCC no later than December 2013. APCo has deferred $6 million as of September 30, 2013 for the Virginia portion of unrecovered costs of the Dresden Plant, excluding $4 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the generation 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 allows the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred ENEC balances and other ENEC-related assets. In August 2012, APCo and WPCo filed a request with the WVPSC for a financing order to securitize a total of $422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of $13 million and related future financing costs of $7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In March 2013, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC which recommended the WVPSC authorize APCo to securitize $376 million plus upfront financing costs. In September 2013, the WVPSC approved the settlement agreement. The securitization bonds are expected to be issued in the fourth quarter of 2013.

In April 2013, APCo and WPCo filed to keep total rates unchanged with a portion of the ENEC to be specifically identified for the amount to be securitized in accordance with the proposed securitization settlement agreement. The remaining ENEC rate is proposed to include (a) the proposed transfer of certain generation facilities from OPCo and the APCo/WPCo merger, (b) construction surcharges and (c) ongoing ENEC costs. In August 2013, the WVPSC approved a settlement that includes (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.

As of September 30, 2013, APCo’s ENEC under-recovery balance of $281 million, net of 2012 and 2013 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding $2 million of unrecognized equity carrying costs and $14 million of other ENEC-related assets.

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. The estimated 2013 earnings component will be reviewed quarterly to determine if any storm costs can be deferred. As of September 30, 2013, there were no deferrals of Virginia storm costs incurred in 2012 or 2013. If this quarterly test allows APCo to defer previously expensed storm costs for future recovery, it could increase future net income and cash flows.

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PSO Rate Matters

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 September 30, 2013, the net book values of NES, Units 3 and 4 were $182 million and $101 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.

I&M Rate Matters

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 the 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 extended 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 September 30, 2013, I&M has incurred $285 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 in a base rate case. I&M was granted recovery through an LCM rider which will be determined by a proceeding in the fourth quarter of 2013 and semi-annual proceedings thereafter. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in its rates. In October 2013, I&M filed an application with the IURC for LCM rider rates to be effective January 2014.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to certain 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 July 2013, a settlement agreement was filed with the IURC. The settlement agreement includes 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. If the IURC approves the settlement agreement, I&M's Indiana 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. A hearing was held at the IURC in August 2013 and a decision is expected by November 2013. As of September 30, 2013, we have incurred costs of $93 million related to the CCT Project, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it could reduce future net income and cash flows.

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 the net book value of Tanners Creek Plant, Units 1-4 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. As of September 30, 2013, the combined net book value of Tanners Creek Plant, Units 1-4 was $342 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 Tanners Creek Plant, Units 1-4, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by OPCo. KPCo also requested costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of September 30, 2013, the net book value of Big Sandy, Unit 2 was $251 million, before cost of removal, including materials and supplies inventory and CWIP. KPCo is currently seeking recovery of these costs with the KPSC. 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 the retirement of Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In July 2013, KPCo, Kentucky Industrial Utility Customers, Inc. (KIUC) and the Sierra Club filed a settlement agreement with the KPSC. The settlement included the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up. The settlement also allows KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement included the authorization to record FGD project costs as a regulatory asset, the conversion of Big Sandy Plant, Unit 1 to natural gas and addressed potential greenhouse gas initiatives on the Mitchell Plant. In October 2013, the KPSC issued an order approving a modified settlement agreement that included a limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order, which is currently pending. Additionally, the order rejected KPCo's request to defer FGD project costs for Big Sandy, Unit 2. Also in October 2013, KPCo filed with the KPSC accepting and agreeing to be bound by the modifications to the settlement agreement. As a result of this order, in the third quarter of 2013, KPCo recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statement of income.

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 includes cost recovery of the pending transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order which modified and approved a settlement agreement relating to the proposed transfer of the one-half interest in the Mitchell Plant, in which KPCo agreed to withdraw this base rate case request. KPCo intends to withdraw this base rate request following the resolution of any potential requests for rehearing or appeals of the KPSC order. Assuming KPCo withdraws the base rate case, current base rates will remain in effect until at least May 2015.

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 to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at NBV OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at NBV OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). These transfers are proposed to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AEPGenCo, the Amos Plant and Mitchell Plant asset transfers to APCo and KPCo and the merger of APCo and WPCo. In May 2013, the IEU petitioned the FERC for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AEPGenCo. OPCo has contested the petition for rehearing, which remains pending before the FERC. Similar asset transfer filings have been made at the KPSC, the Virginia SCC and the WVPSC. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

Additionally, the AEP East Companies requested FERC approval, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate 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. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision is pending at the FERC.

Additionally, FERC approval was sought for a power supply agreement between AEPGenCo and OPCo. This agreement provides for AEPGenCo 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 an auction from January 1, 2014 through December 31, 2014.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by recent 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. 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 corporate separation is approved as filed, for any AEPGenCo generation not serving OPCo’s retail load, AEPGenCo’s results of operations will be largely determined by prevailing market conditions effective January 1, 2014. If incurred costs are not ultimately recovered, it could reduce future net income and cash flows and impact financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2012 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit

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

We have two revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters of credit. As of September 30, 2013, the maximum future payments for letters of credit issued under the revolving credit facilities were $185 million with maturities ranging from October 2013 to November 2014.

We have $402 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $407 million. The letters of credit have maturities ranging from March 2014 to March 2015.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of September 30, 2013, SWEPCo has collected approximately $63 million through a rider for final mine closure and reclamation costs, of which $13 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $50 million is recorded in Asset Retirement Obligations on our condensed balance sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the 2012 Annual Report "Dispositions" section of Note 6. As of September 30, 2013, there were no material liabilities recorded for any indemnifications.

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 September 30, 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.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $14 million and $15 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2013.

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% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. 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.

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 CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. 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 generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $10 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES

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

Nuclear Incident Insurance

Prior to April 2013, I&M carried insurance coverage for a nuclear or nonnuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of $2.8 billion. Effective April 2013, insurance coverage for a nonnuclear incident at the Cook Plant was reduced to $1.7 billion. 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

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in Federal 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. In October 2013, we filed a motion to dismiss the case. 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.

5. ACQUISITION AND IMPAIRMENTS

ACQUISITION

2012

BlueStar Energy (Generation and Marketing segment)

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

IMPAIRMENTS

2013

Turk Plant (Utility Operations segment)

In the third quarter of 2013, SWEPCo recorded a pretax write-off of $111 million in Asset Impairments and Other Related Charges on the statement of income related to AFUDC on the Turk Plant that was included in the Texas capital cost cap. See the “2012 Texas Base Rate Case” section of Note 3.

Big Sandy Plant, Unit 2 FGD Project (Utility Operations 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 3.

Muskingum River Plant, Unit 5 (Utility Operations 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 OPCo's 600 MW Muskingum River Plant, Unit 5 (MR5) coal-fired generation plant. Under the modification to the consent decree, OPCo has 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, OPCo 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

Turk Plant (Utility Operations segment)

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

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2013	2012	2013	2012
	(in millions)			
Service Cost	$ 17	$ 19	$ 5	$ 12
Interest Cost	51	56	18	26
Expected Return on Plan Assets	(69)	(80)	(27)	(26)
Amortization of Transition Obligation	-	-	-	1
Amortization of Prior Service Cost (Credit)	1	-	(17)	(5)
Amortization of Net Actuarial Loss	45	42	16	14
Net Periodic Benefit Cost (Credit)	$ 45	$ 37	$ (5)	$ 22

Other Postretirement

	Pension Plans		Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in millions)			
Service Cost	$ 52	$ 57	$ 17	$ 35
Interest Cost	152	167	53	78
Expected Return on Plan Assets	(208)	(239)	(80)	(76)
Amortization of Transition Obligation	-	-	-	1
Amortization of Prior Service Cost (Credit)	2	-	(52)	(14)
Amortization of Net Actuarial Loss	137	117	48	43
Net Periodic Benefit Cost (Credit)	$ 135	$ 102	$ (14)	$ 67

7. BUSINESS SEGMENTS

As outlined in our 2012 Annual Report, our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Utility Operations

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

Transmission Operations

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

AEP River Operations

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

Generation and Marketing

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

The remainder of our activities is presented as All Other. While not considered a reportable segment, All Other includes Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The tables below present our reportable segment information for the three and nine months ended September 30, 2013 and 2012 and balance sheet information as of September 30, 2013 and December 31, 2012. These amounts include certain estimates and allocations where necessary.

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Three Months Ended September 30, 2013							
Revenues from:							
External Customers	$ 3,788	$ 8	$ 125	$ 251	$ 4	$ -	$ 4,176
Other Operating Segments	31	18	5	-	3	(57)	-
Total Revenues	$ 3,819	$ 26	$ 130	$ 251	$ 7	$ (57)	$ 4,176
Net Income (Loss)	$ 409	$ 22	$ (1)	$ 4	$ -	$ -	$ 434

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Three Months Ended September 30, 2012							
Revenues from:							
External Customers	$ 3,811	$ 3	$ 142	$ 194	$ 6	$ -	$ 4,156
Other Operating Segments	28	7	5	-	4	(44)	-
Total Revenues	$ 3,839	$ 10	$ 147	$ 194	$ 10	$ (44)	$ 4,156
Net Income (Loss)	$ 471	$ 14	$ (1)	$ 10	$ (6)	$ -	$ 488

	Utility Operations	Transmission Operations	Nonutility Operations AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Nine Months Ended September 30, 2013							
Revenues from:							

External Customers	$	10,520	$	18	$	365	$	671	$	10	$	-	$	11,584
Other Operating Segments		94		35		15		-		6		(150)		-
Total Revenues	$	10,614	$	53	$	380	$	671	$	16	$	(150)	$	11,584
Net Income (Loss)	$	980	$	53	$	(12)	$	15	$	101	$	-	$	1,137

					Nonutility Operations									
		Utility Operations		Transmission Operations		AEP River Operations		Generation and Marketing		All Other (a)		Reconciling Adjustments		Consolidated
						(in millions)								
Nine Months Ended September 30, 2012														
Revenues from:														
External Customers	$	10,407	$	5	$	477	$	427	$	16	$	-	$	11,332
Other Operating Segments		75		10		16		-		7		(108)		-
Total Revenues	$	10,482	$	15	$	493	$	427	$	23	$	(108)	$	11,332
Net Income (Loss)	$	1,220	$	31	$	11	$	4	$	(25)	$	-	$	1,241

			Nonutility Operations				
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
September 30, 2013							
Total Property, Plant and Equipment	$ 56,745	$ 1,296	$ 637	$ 627	$ 8	$ (269)	$ 59,044
Accumulated Depreciation and Amortization	18,791	7	182	268	8	(82)	19,174
Total Property, Plant and Equipment - Net	$ 37,954	$ 1,289	$ 455	$ 359	$ -	$ (187)	$ 39,870
Total Assets	$ 51,598	$ 1,809	$ 650	$ 1,009	$ 17,874	$ (17,977)(c)	$ 54,963

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

(a) All Other includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
(b) Includes eliminations due to an intercompany capital lease.
(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact. To accomplish our objectives, we primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for “Derivatives and Hedging.” Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

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

The following table represents the gross notional volume of our outstanding derivative contracts as of September 30, 2013 and December 31, 2012:

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	September 30, 2013 (in millions)	December 31, 2012	Unit of Measure
Commodity:			
Power	464	498	MWhs
Coal	6	10	Tons
Natural Gas	141	147	MMBtus
Heating Oil and Gasoline	5	6	Gallons
Interest Rate	$ 201	$ 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 condensed 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 September 30, 2013 and December 31, 2012 condensed balance sheets, we netted $5 million and $7 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $26 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 our condensed balance sheets as of September 30, 2013 and December 31, 2012:

Fair Value of Derivative Instruments
September 30, 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	$ 441	$ 19	$ 4	$ 464	$ (293)	$ 171
Long-term Risk Management Assets	433	6	1	440	(126)	314
Total Assets	874	25	5	904	(419)	485
Current Risk Management Liabilities	389	23	1	413	(311)	102
Long-term Risk Management Liabilities	301	4	13	318	(136)	182
Total Liabilities	690	27	14	731	(447)	284
Total MTM Derivative Contract Net Assets (Liabilities)	$ 184	$ (2)	$ (9)	$ 173	$ 28	$ 201

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)

			(in millions)			
Current Risk Management Assets	$ 589	$ 32	$ 3	$ 624	$ (433)	$ 191
Long-term Risk Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ (12)	$ (37)	$ 139	$ 51	$ 190

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts 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 three and nine months ended September 30, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2013 and 2012

	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	2013	2012	2013	2012
		(in millions)		
Utility Operations Revenues	$ 4	$ 5	$ 17	$ 19
Other Revenues	9	20	39	28
Regulatory Assets (a)	-	2	(3)	(35)
Regulatory Liabilities (a)	(5)	(14)	(10)	12
Total Gain (Loss) on Risk Management Contracts	$ 8	$ 13	$ 43	$ 24

(a)

Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed 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 condensed statements of income on an accrual basis.

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

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

Accounting for Fair Value Hedging Strategies

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

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our condensed statements of income. During the three and nine months ended September 30, 2013, we recognized gains of $4 million and losses of $8 million, respectively, on our hedging instruments and offsetting losses of $4 million and gains of $8 million, respectively, on our long-term debt. During the three and nine months ended September 30, 2012, we recognized gains of $1 million and $3 million, respectively, on our hedging instruments and offsetting losses of $1 million and $3 million, respectively, on our long-term debt. During the three and nine months ended September 30, 2013 and 2012, 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 our condensed 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 our condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on our condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2013 and 2012, 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 our condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our condensed statements of income. During the three and nine months ended September 30, 2013 and 2012, 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 our condensed balance sheets into Interest Expense on our condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2013 and 2012, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Depreciation and Amortization expense on our condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2013, we did not designate any foreign currency derivatives as cash flow hedges. During the three and nine months ended September 30, 2012, we designated foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2013 and 2012, 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 our condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2013 and 2012, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of September 30, 2013 and December 31, 2012 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2013

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 9	$ -	$ 9
Hedging Liabilities (a)	11	2	13
AOCI Gain (Loss) Net of Tax	(1)	(24)	(25)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(2)	(4)	(6)

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

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

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed 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 September 30, 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 27 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 September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 3	$ 7
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	39	32
Amount Attributable to RTO and ISO Activities	38	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 September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual		

Netting Arrangements	$	341	$	469
Amount of Cash Collateral Posted		1		8
Additional Settlement Liability if Cross Default Provision is Triggered		258		328

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. Our market risk oversight staff independently monitors our valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations. 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 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 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.

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 September 30, 2013 and December 31, 2012 are summarized in the following table:

	September 30, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
		(in millions)		
Long-term Debt	$ 17,568	$ 19,316	$ 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.

The following is a summary of Other Temporary Investments:

	September 30, 2013			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
		(in millions)		
Restricted Cash (a)	$ 188	$ -	$ -	$ 188
Fixed Income Securities:				
Mutual Funds	79	-	-	79
Equity Securities - Mutual Funds	13	8	-	21
Total Other Temporary Investments	$ 280	$ 8	$ -	$ 288

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

(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 three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
	(in millions)			
Proceeds from Investment Sales	$ -	$ -	$ -	$ -
Purchases of Investments	6	-	17	1
Gross Realized Gains on Investment Sales	-	-	-	-
Gross Realized Losses on Investment Sales	-	-	-	-

As of September 30, 2013 and December 31, 2012, we had no Other Temporary Investments with an unrealized loss position. As of September 30, 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.

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three and nine months ended September 30, 2013 and 2012, see Note 2.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

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

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both fixed income and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and fixed income investments held in these trusts and generally intends to sell fixed income 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. I&M records unrealized gains and other-than-temporary impairments from securities in the 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. The trust assets are recorded by jurisdiction and may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments as of September 30, 2013 and December 31, 2012:

	September 30, 2013			December 31, 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	$ 15	$ -	$ -	$ 17	$ -	$ -
Fixed Income Securities:						
United States Government	621	34	(3)	648	58	(1)
Corporate Debt	38	2	(2)	35	5	(1)

State and Local Government	244	1	-	270	1	(1)
Subtotal Fixed Income Securities	903	37	(5)	953	64	(3)
Equity Securities - Domestic	921	415	(81)	736	285	(77)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,839	$ 452	$ (86)	$ 1,706	$ 349	$ (80)

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The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in millions)			
Proceeds from Investment Sales	$ 250	$ 182	$ 635	$ 699
Purchases of Investments	264	199	676	744
Gross Realized Gains on Investment Sales	4	2	16	7
Gross Realized Losses on Investment Sales	2	1	12	3

The adjusted cost of fixed income securities was $866 million and $889 million as of September 30, 2013 and December 31, 2012, respectively. The adjusted cost of equity securities was $506 million and $451 million as of September 30, 2013 and December 31, 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2013 was as follows:

	Fair Value of Fixed Income Securities (in millions)
Within 1 year	$ 74
1 year – 5 years	378
5 years – 10 years	210
After 10 years	241
Total	$ 903

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 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
September 30, 2013

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Cash and Cash Equivalents (a)	$ 14	$ 1	$ -	$ 132	$ 147
Other Temporary Investments					
Restricted Cash (a)	173	7	-	8	188
Fixed Income Securities:					
Mutual Funds	79	-	-	-	79
Equity Securities - Mutual Funds (b)	21	-	-	-	21
Total Other Temporary Investments	273	7	-	8	288
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	34	680	147	(399)	462
Cash Flow Hedges:					
Commodity Hedges (c)	2	22	-	(15)	9
Fair Value Hedges	-	2	-	3	5
De-designated Risk Management Contracts (e)	-	-	-	9	9
Total Risk Management Assets	36	704	147	(402)	485
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	6	-	-	9	15
Fixed Income Securities:					
United States Government	-	621	-	-	621
Corporate Debt	-	38	-	-	38
State and Local Government	-	244	-	-	244
Subtotal Fixed Income Securities	-	903	-	-	903
Equity Securities - Domestic (b)	921	-	-	-	921
Total Spent Nuclear Fuel and Decommissioning Trusts	927	903	-	9	1,839
Total Assets	$ 1,250	$ 1,615	$ 147	$ (253)	$ 2,759
Liabilities:					

Risk Management Liabilities										
Risk Management Commodity Contracts (c) (d)	$	40	$	613	$	24	$	(418)	$	259
Cash Flow Hedges:										