AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 25, 2014

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 June 30, 2014
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.

Large accelerated filer X   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 July 24, 2014
American Electric Power Company, Inc.	488,670,382 ($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
June 30, 2014

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.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEP Transmission Holdco and an intermediate holding company that owns seven wholly-owned transmission companies.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.

ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.

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Term	Meaning
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.

PIRR	Phase-In Recovery Rider.
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.

Term	Meaning
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
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, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
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 2013 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 ref 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.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generation capacity and the performance of our generation plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generation capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation, cost recovery and/or profitability of our generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing, alternative or distributed sources of generation.

Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
- The transition to market for generation in Ohio, including the implementation of ESPs.
- Our ability to successfully and profitably manage our separate competitive generation assets.
- 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 of such volatility 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 2013 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

Customer Demand

In comparison to 2013, heating degree days for the six months ended June 30, 2014 were up 32% in our western region and 20% in our eastern region. Our weather-normalized retail sales volumes for the second quarter of 2014 decreased by 0.5% from their levels for the second quarter of 2013 and increased by 0.6% for the first six months of 2014 from their levels for the first six months of 2013. In comparison to 2013, our industrial sales volume decreased 0.5% and 1.6% for the three and six months ended June 30, 2014, respectively, due mainly to the closure of Ormet, a large aluminum company. Excluding Ormet, our six months ended June 30, 2014 industrial sales volumes increased 3.4% over the six months ended June 30, 2013. Following Ormet's closure in October 2013, the loss of Ormet's load will not have a material impact on future gross margin because power previously sold to Ormet will be available for sale into generally higher priced wholesale markets.

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) wholesale sales, (c) deferral of unrecovered capacity costs, (d) RSR collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation & Marketing segment which targets retail customers, both within and outside of our retail service territory.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo’s deferred fuel costs in rates beginning September 2012. As of June 30, 2014, OPCo’s net deferred fuel balance was $411 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo’s net deferred fuel costs balance up to the full amount.

June 2012 - May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the 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 OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April

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and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of June 30, 2014, OPCo's incurred deferred capacity costs balance was $396 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. In February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. In May 2014, OPCo conducted an additional energy-only auction for 25% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 25% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. A final audit report is expected in the third quarter of 2014.

Proposed June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to competitively procured SSO supply. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement rider (PPA) that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. Additionally, in July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the Distribution Investment Rider and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014.

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

2012 Texas Base Rate Case

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In May 2014, intervenors filed appeals of the order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses. If any part of the PUCT order is overturned it could reduce future net income and cash flows and impact financial condition. See the “2012 Texas Base Rate Case” section of Note 4.

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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. 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 4.

2014 Oklahoma Base Rate Case

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

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $7 million of revenues in 2014 and increases to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, to be effective November 2014. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. If the OCC were to disallow any portion of this settlement agreement, it could reduce future net income and cash flows and impact financial condition. See the “2014 Oklahoma Base Rate Case” section of Note 4.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request an increase in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to the change in the expected service life of certain plants. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 Virginia Biennial Base Rate Case” section of Note 4.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates and requested amortization of $89 million over five years related to 2012 West

Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover total vegetation management costs. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 West Virginia Base Rate Case” section of Note 4.

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PJM Capacity Market

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

PJM Auction Period	PJM Base Auction Price (per MW day)	
June 2013 through May 2014	$	27.73
June 2014 through May 2015		125.99
June 2015 through May 2016		136.00
June 2016 through May 2017		59.37
June 2017 through May 2018		120.00

We expect a significant decline in AGR capacity revenues after May 2015 when the Power Supply Agreement between AGR and OPCo ends. Additionally, we expect a decline in AGR capacity revenues from June 2016 through May 2017 based upon the decrease in the PJM base auction price.

In 2013, AEP formed a coalition with other utility companies to address mutual concerns related to the PJM capacity auction process. The advocacy work included: (a) assuring that capacity imports had firm transmission and could be dispatched by PJM as well as establishing more limiting criteria, (b) placing limits on the number of MWs of summer-only demand response to assure more year-round reliability, (c) modification and enforcement of the dispatch of demand response to better reflect real-time capacity requirements and (d) tightening of rules for incremental auctions in which speculative bidders sell resources in the base auction and buy back that capacity in an incremental auction, resulting in no additional capacity and artificially suppressing market prices.

PJM made four FERC filings related to these four issues beginning in the fall of 2013. FERC accepted the majority of the PJM recommendations in the first three filings. However, FERC rejected the fourth filing on incremental auctions, but set the docket for a technical conference for further discussion.

SPP Integrated Power Market

In March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In the past, PSO and SWEPCo would satisfy their load requirements with their own generation resources or through the Operating Agreement. In the new integrated power market, PSO and SWEPCo operate as standalone entities by offering their respective generation into the SPP power market, which then economically dispatches the resources. This change further enables retail customers to obtain low cost power through either internal generation or power purchases from the SPP market. The new integrated power market now operates in a similar manner as the PJM power market for the AEP East Companies. No significant impact on results of operations is expected due to this change.

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 June 30, 2014, SWEPCo has incurred $72 million in costs related to these projects. SWEPCo will seek to recover these project costs from customers through filings at the state commissions and FERC. These environmental projects could be impacted

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by pending carbon emission regulations. See "CO_2 Regulation" section of “Environmental Issues” below. As of June 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $297 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of June 30, 2014, I&M has incurred costs of $439 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M’s proposed project with the exception of an estimated $23 million related to certain items which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC. In May 2014, the IURC issued a final order approving the LCM rider rates that were implemented in 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 the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project.

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

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 - Rate Matters, Note 6 - Commitments, Guarantees and Contingencies and the “Litigation” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2013 Annual Report. Additionally, see Note 4 - Rate Matters and Note 5 - 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 U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss the case, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

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 2013 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of June 30, 2014, 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 generating facilities. Based upon our estimates, investment to meet these requirements ranges from approximately $3 billion to $3.5 billion through 2020. Several proposed regulations issued during 2014, including CO_2 and Clean Water Act, are currently under review and we cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet; however, the costs may be substantial. These amounts include investments to convert some of our coal generation 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 (SIPs) or federal implementation plans (FIPs) 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)
AGR	Kammer Plant	630
AGR	Muskingum River Plant	1,440
AGR	Picway Plant	100
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
KPCo	Big Sandy Plant, Unit 2	800
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of June 30, 2014, the net book value of the AGR units listed above was zero. The net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the regulated plants in the table above was $985 million.

In addition, we are in the process of obtaining permits and other necessary regulatory approvals for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas. As of June 30, 2014, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of Big Sandy Plant, Unit 1 was $99 million.

PSO received Federal EPA approval of the Oklahoma SIP, in February 2014, related to the environmental compliance plan for Northeastern Station, Unit 3.

Volatility in fuel 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.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation’s air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The U.S. Court of Appeals for the District of Columbia Circuit issued an order in 2011 staying the effective date of the rule pending judicial review. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision in part and remanded the case to the U.S. Court of

Appeals for the District of Columbia Circuit. Nearly all of the states in which our power plants are located are covered by CAIR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012. See “Mercury and Other Hazardous Air Pollutants (HAPs) Regulation” section below.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA has proposed to include CO_2 emissions in standards that apply to new electric utility units and will consider whether such standards are appropriate for other source categories in the future. See "CO_2 Regulation" section below.

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

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

Cross-State Air Pollution Rule (CSAPR)

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

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In 2011, the court granted the motions for stay. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "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

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was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The parties have filed motions to govern further proceedings. The Federal EPA has filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. Until the court acts on this motion, CAIR will remain in effect. Separate appeals of the Error Corrections Rule and the further revisions have been filed but no briefing schedules have been established. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of several nonmercury metals) 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. Petitions for administrative reconsideration and judicial review were filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule.

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. We have obtained a one-year administrative extension at several units to facilitate 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 remain concerned about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards schedule and other environmental requirements.

CO_2 Regulation

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. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO_2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. The proposal was published in the Federal Register in January 2014.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs 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.” The Federal EPA issued proposed guidelines establishing state goals for CO_2 emissions from existing EGUs and proposed regulations governing emissions of CO_2 from modified and reconstructed EGUs in June 2014 and comments are due in October 2014. The guidelines use a “portfolio” approach to reducing emissions from existing sources that includes

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efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, expanding renewable resources and increasing customer energy efficiency. The standards for modified and reconstructed units include several options, including use of historic baselines or energy efficiency audits to establish source-specific CO_2 emission rates or to limit CO_2 emissions to no more than 1,900 pounds per MWh at larger coal units and 2,100 pounds per MWh at smaller coal units. These proposed regulations are currently under review. 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 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. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied a petition for rehearing. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA must undertake additional rulemaking to implement the court's decision and establish an appropriate level.

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 and also FGD gypsum generated at some coal fired plants. 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 disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of issues.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and sought additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act (CWA) for utility facilities. In October 2013, the U.S. District Court for the District of Columbia issued a final order partially ruling in favor of the Federal EPA for dismissal of two counts, ruling in favor of the environmental organizations on one count and directing the Federal EPA to provide the court with a proposed schedule for completion of the rulemaking. The court established December 19, 2014 as the Federal EPA's deadline for publication of the rule.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities. We 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. In 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. The final rule was released by the Federal EPA in May 2014 and affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years.

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 September 2015. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of our long-term plans. We continue to review the proposal in detail to evaluate whether our plants are currently meeting the proposed limitations, what technologies have been incorporated into our long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. We submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which we are members.

In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This proposed jurisdictional definition will apply to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. We agree that clarity and efficiency in the permitting process is needed. We are concerned that the proposed rule introduces new concepts and could subject more of our operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. We will continue to evaluate the rule and its financial impact on the AEP System. We plan to submit comments and also participate in the preparation of comments to be 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.

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 2013 Form 10-K under the headings entitled "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 Vertically Integrated Utilities segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy to serve SSO customers and provides capacity for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

The table below presents Net Income (Loss) by segment for the three and six months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Vertically Integrated Utilities	$155	$153	$434	$334
Transmission and Distribution Utilities	90	75	187	162
AEP Transmission Holdco	47	19	71	31
Generation & Marketing	98	(9)	261	76
AEP River Operations	3	(9)	6	(11)
Corporate and Other (a)	(2)	110	(7)	111
Net Income	$391	$339	$952	$703

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

AEP CONSOLIDATED

Second Quarter of 2014 Compared to Second Quarter of 2013

Net Income increased from $339 million in 2013 to $391 million in 2014 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- An increase in transmission investment which resulted in higher revenues and income.
- Higher market prices.
- The second quarter 2013 impairment of Muskingum River Plant, Unit 5.

These increases were partially offset by:

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

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Net Income increased from $703 million in 2013 to $952 million in 2014 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- An increase in transmission investment which resulted in higher revenues and income.
- Higher market prices and increased sales volumes.
- An increase in weather-related usage.
- The second quarter 2013 impairment of Muskingum River Plant, Unit 5.

These increases were partially offset by:

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

Our results of operations are discussed below by operating segment.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
	(in millions)			
Revenues	$2,252	$2,302	$4,838	$4,817
Fuel and Purchased Electricity	934	1,064	2,028	2,265
Gross Margin	1,318	1,238	2,810	2,552
Other Operation and Maintenance	618	551	1,194	1,129
Depreciation and Amortization	252	234	515	469
Taxes Other Than Income Taxes	87	93	183	184
Operating Income	361	360	918	770
Interest and Investment Income	—	4	1	7
Carrying Costs Income	2	4	1	5
Allowance for Equity Funds Used During Construction	11	9	21	18
Interest Expense	(132)	(136)	(263)	(272)
Income Before Income Tax Expense and Equity Earnings	242	241	678	528
Income Tax Expense	88	89	245	195
Equity Earnings of Unconsolidated Subsidiaries	1	1	1	1
Net Income	$155	$153	$434	$334

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30, 2014	2013		Six Months Ended June 30, 2014	2013	
	(in millions of KWhs)					
Retail:						
Residential	6,716	6,878		17,621	16,667	
Commercial	6,122	6,158		12,237	12,003	
Industrial	9,025	8,707		17,357	16,968	
Miscellaneous	577	566		1,132	1,115	
Total Retail	22,440	22,309		48,347	46,753	
Wholesale (a)	8,602	NM	(b)	18,786	NM	(b)

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.

(b) 2014 is not comparable to 2013 due to the 2013 asset transfers related to corporate separation in Ohio on December 31, 2013 and the termination of the Interconnection Agreement effective January 1, 2014.

NM Not meaningful.

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in degree days)			
Eastern Region				
Actual - Heating (a)	118	148	2,246	1,853
Normal - Heating (b)	138	140	1,731	1,735
Actual - Cooling (c)	362	350	362	350
Normal - Cooling (b)	324	324	329	329
Western Region				
Actual - Heating (a)	47	94	1,233	1,009
Normal - Heating (b)	33	31	920	921
Actual - Cooling (c)	674	673	680	683
Normal - Cooling (b)	686	686	710	710

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

Second Quarter of 2014 Compared to Second Quarter of 2013
Reconciliation of Second Quarter of 2013 to Second Quarter of 2014
Net Income from Vertically Integrated Utilities
(in millions)

Second Quarter of 2013	$153
Changes in Gross Margin:	
Retail Margins	61
Off-system Sales	21
Transmission Revenues	6
Other Revenues	(8)
Total Change in Gross Margin	80
Changes in Expenses and Other:	
Other Operation and Maintenance	(67)
Depreciation and Amortization	(18)
Taxes Other Than Income Taxes	6
Interest and Investment Income	(4)
Carrying Costs Income	(2)
Allowance for Equity Funds Used During Construction	2
Interest Expense	4
Total Change in Expenses and Other	(79)
Income Tax Expense	1
Second Quarter of 2014	$155

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 $61 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- APCo - $46 million.
- SWEPCo - $21 million.

For the rate increases described above, $26 million of these increases relate to riders/trackers which have corresponding increases in expense items below.

- Margins from Off-system Sales increased $21 million primarily due to higher market prices and increased sales volumes.
- Transmission Revenues increased $6 million primarily due to increased investment in the PJM region.
- Other Revenues decreased $8 million primarily due to a decrease in barging. This decrease in barging is a result of the River Transportation Division (RTD) no longer serving plants transferred from OPCo to AGR at December 31, 2013 as a result of corporate separation. The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses increased $67 million primarily due to the following:
  - A $31 million increase in transmission expenses primarily related to PJM and SPP services.
  - A $23 million increase in plant outage and maintenance expenses.
  - A $14 million increase in recoverable PJM and other expenses currently fully recovered in rate recovery riders/trackers.
  - A $6 million increase in distribution expenses related to various distribution services and forestry expenses.

  These increases were partially offset by:
  - A $9 million decrease in storm-related expenses primarily in APCo's service territory.
  - A $9 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a decrease in Retail Margins discussed above.
- Depreciation and Amortization expenses increased $18 million primarily due to overall higher depreciable base.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013
Reconciliation of Six Months Ended June 30, 2013 to Six Months Ended June 30, 2014
Net Income from Vertically Integrated Utilities
(in millions)

Six Months Ended June 30, 2013	$334	
Changes in Gross Margin:		
Retail Margins	163	
Off-system Sales	106	
Transmission Revenues	16	
Other Revenues	(27	)
Total Change in Gross Margin	258	
Changes in Expenses and Other:		
Other Operation and Maintenance	(65	)
Depreciation and Amortization	(46	)
Taxes Other Than Income Taxes	1	
Interest and Investment Income	(6	)
Carrying Costs Income	(4	)
Allowance for Equity Funds Used During Construction	3	
Interest Expense	9	
Total Change in Expenses and Other	(108	)
Income Tax Expense	(50	)
Six Months Ended June 30, 2014	$434	

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 $163 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories which include:
    - APCo - $72 million.
    - SWEPCo - $45 million.
    - KPCo - $26 million.
    - I&M - $11 million.

    For the rate increases described above, $50 million of these increases relate to riders/trackers which have corresponding increases in expense items below.
  - A $52 million increase due to favorable weather conditions.

  These increases were partially offset by:
  - A $40 million increase in PJM expenses net of recovery or offsets.
- Margins from Off-system Sales increased $106 million primarily due to higher market prices and increased sales volumes.
- Transmission Revenues increased $16 million primarily due to increased investment in the PJM region.
- Other Revenues decreased $27 million primarily due to a decrease in barging. This decrease in barging is a result of the RTD no longer serving plants transferred from OPCo to AGR at December 31, 2013 as a result of corporate separation. The decrease in RTD revenue was offset by a decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses increased $65 million primarily due to the following:
  - A $48 million increase in transmission expenses primarily related to PJM and SPP services.
  - A $26 million increase in plant outage and maintenance expenses.
  - A $25 million increase due to an agreement reached to settle an insurance claim in the first quarter of 2013.
  - A $21 million increase in recoverable PJM and other expenses currently fully recovered in rate recovery riders/trackers.
  - A $12 million increase in distribution expenses related to various distribution services and forestry expenses.

  These increases were partially offset by:
  - 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 $23 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a decrease in Retail Margins discussed above.
  - A $20 million decrease in storm-related expenses primarily in APCo's service territory.
- Depreciation and Amortization expenses increased $46 million primarily due to overall higher depreciable base.
- Interest Expense decreased $9 million primarily due to the following:
  - A $5 million decrease due to the retirement of KPCo Senior Unsecured Notes in the third quarter of 2013.
  - A $4 million decrease due to rate approvals in Louisiana and Texas and an increase in the debt component of AFUDC due to increased transmission and environmental projects.
- Income Tax Expense increased $50 million primarily due to an increase in pretax book income.

TRANSMISSION AND DISTRIBUTION UTILITIES

	Three Months Ended June 30,		Six Months Ended June 30,	
Transmission and Distribution Utilities	2014	2013	2014	2013
	(in millions)			
Revenues	$1,134	$1,064	$2,349	$2,198
Fuel and Purchased Electricity	343	405	746	854
Amortization of Generation Deferrals	25	—	56	—
Gross Margin	766	659	1,547	1,344
Other Operation and Maintenance	298	219	591	463
Depreciation and Amortization	156	151	317	284
Taxes Other Than Income Taxes	108	105	227	209
Operating Income	204	184	412	388
Interest and Investment Income	3	—	6	1
Carrying Costs Income	7	4	14	7
Allowance for Equity Funds Used During Construction	2	—	5	2
Interest Expense	(72)	(72)	(142)	(147)
Income Before Income Tax Expense	144	116	295	251
Income Tax Expense	54	41	108	89
Net Income	$90	$75	$187	$162

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013		2014	2013	
	(in millions of KWhs)					
Retail:						
Residential	5,559	5,752		13,086	12,218	
Commercial	6,314	6,394		12,216	12,100	
Industrial	5,630	5,895		10,773	11,395	
Miscellaneous	182	180		353	340	
Total Retail (a)	17,685	18,221		36,428	36,053	
Wholesale (b)	453	NM	(c)	1,152	NM	(c)

(a) Represents energy delivered to distribution customers.
(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.
(c) 2014 is not comparable to 2013 due to the 2013 asset transfers related to corporate separation in Ohio on December 31, 2013 and the termination of the Interconnection Agreement effective January 1, 2014.
NM Not meaningful.

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

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in degree days)			
Eastern Region				
Actual - Heating (a)	130	193	2,539	2,164
Normal - Heating (b)	187	190	2,067	2,075
Actual - Cooling (c)	362	346	362	346
Normal - Cooling (b)	280	277	283	280
Western Region				
Actual - Heating (a)	2	8	302	143
Normal - Heating (b)	4	4	200	205
Actual - Cooling (d)	872	940	942	1,077
Normal - Cooling (b)	904	902	1,012	1,007

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

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Second Quarter of 2014 Compared to Second Quarter of 2013
Reconciliation of Second Quarter of 2013 to Second Quarter of 2014
Net Income from Transmission and Distribution Utilities
(in millions)

Second Quarter of 2013	$75
Changes in Gross Margin:	
Retail Margins	74
Transmission Revenues	33
Total Change in Gross Margin	107
Changes in Expenses and Other:	
Other Operation and Maintenance	(79)
Depreciation and Amortization	(5)
Taxes Other Than Income Taxes	(3)
Interest and Investment Income	3
Carrying Costs Income	3
Allowance for Equity Funds Used During Construction	2
Total Change in Expenses and Other	(79)
Income Tax Expense	(13)
Second Quarter of 2014	$90

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

- Retail Margins increased $74 million primarily due to the following:
  - A $33 million increase in PJM revenues that are offset in expense items discussed below.
  - A $19 million increase for TCC and TNC primarily due to favorable prices.
  - A $14 million increase in OPCo revenues primarily associated with the Distribution Investment Rider (DIR) and Universal Service Fund (USF) surcharge. Of these increases, $2 million relate to riders/trackers which have corresponding increases in other expense items below.
  - A $13 million increase in OPCo revenues associated with the Storm Damage Recovery Rider implemented in April 2014. This increase in Retail Margins is offset by an increase in expense items discussed below.
- Transmission Revenues increased $33 million primarily due to increased transmission investment, increased transmission revenues from customers who have switched to alternative CRES providers and rate increases for customers in the PJM region. The increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.

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

- Other Operation and Maintenance expenses increased $79 million primarily due to the following:
  - A $55 million increase in recoverable PJM and other expenses currently fully recovered in rate recovery riders/trackers.
  - A $12 million increase in transmission expenses primarily related to PJM services.
  - A $5 million increase in distribution expenses related to various distribution services and programs.
  - A $3 million increase in storm-related expenses primarily in OPCo's service territory.
- Depreciation and Amortization expenses increased $5 million primarily due to the following:
  - A $3 million increase in amortization related to TCC and OPCo securitizations, which are offset in Retail Margins above.
  - A $3 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Income Tax Expense increased $13 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013
Reconciliation of Six Months Ended June 30, 2013 to Six Months Ended June 30, 2014
Net Income from Transmission and Distribution Utilities
(in millions)

Six Months Ended June 30, 2013	$162
Changes in Gross Margin:	
Retail Margins	147
Transmission Revenues	47
Other Revenues	9
Total Change in Gross Margin	203
Changes in Expenses and Other:	
Other Operation and Maintenance	(128)
Depreciation and Amortization	(33)
Taxes Other Than Income Taxes	(18)
Interest and Investment Income	5
Carrying Costs Income	7
Allowance for Equity Funds Used During Construction	3
Interest Expense	5
Total Change in Expenses and Other	(159)
Income Tax Expense	(19)
Six Months Ended June 30, 2014	$187

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

- Retail Margins increased $147 million primarily due to the following:
  - A $48 million increase for TCC and TNC primarily due to favorable prices and increased usage.
  - A $28 million increase in OPCo revenues primarily associated with the DIR and USF surcharge. Of these increases, $12 million relate to riders/trackers which have corresponding increases in other expense items below.
  - A $21 million increase in PJM revenues that are offset in expense items discussed below.
  - A $17 million increase primarily due to increased connected load for OPCo.
  - A $13 million increase in OPCo revenues associated with the Storm Damage Recovery Rider. This increase in Retail Margins is offset by an increase in expense items discussed below.
- Transmission Revenues increased $47 million primarily due to increased transmission investment, increased transmission revenues from customers who have switched to alternative CRES providers and rate increases for customers in the PJM region. The increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.
- Other Revenues increased $9 million primarily due to increased Texas securitization revenues.

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

- Other Operation and Maintenance expenses increased $128 million primarily due to the following:
  - An $80 million increase in recoverable PJM and other expenses currently fully recovered in rate recovery riders/trackers.
  - A $13 million increase in expenses related to various distribution services and programs.
  - An $11 million increase in transmission expenses primarily related to PJM and forestry expenses.
  - A $10 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 an increase in Retail Margins above.
  - A $9 million increase in storm-related expenses primarily in OPCo's service territory.
- Depreciation and Amortization expenses increased $33 million primarily due to the following:
  - A $22 million increase in amortization related to TCC and OPCo securitizations, which are offset in Retail Margins.
  - A $6 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $18 million primarily due to increased property taxes.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income.

AEP TRANSMISSION HOLDCO

Second Quarter of 2014 Compared to Second Quarter of 2013

Net Income from our AEP Transmission Holdco segment increased from $19 million in 2013 to $47 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Net Income from our AEP Transmission Holdco segment increased from $31 million in 2013 to $71 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

GENERATION & MARKETING

	Three Months Ended June 30,		Six Months Ended June 30,	
Generation & Marketing	2014	2013	2014	2013
	(in millions)			
Revenues	$913	$892	$2,164	$1,812
Fuel, Purchased Electricity and Other	560	548	1,365	1,116
Gross Margin	353	344	799	696
Other Operation and Maintenance	125	112	241	236
Asset Impairments and Other Related Charges	—	154	—	154
Depreciation and Amortization	56	61	113	123
Taxes Other Than Income Taxes	13	17	25	33
Operating Income	159	—	420	150
Interest and Investment Income	1	2	2	2
Interest Expense	(11)	(15)	(23)	(34)
Income (Loss) Before Income Tax Expense (Credit)	149	(13)	399	118
Income Tax Expense (Credit)	51	(4)	138	42
Net Income (Loss)	$98	$(9)	$261	$76

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions of MWhs)			
Fuel Type:				
Coal	9	9	21	19
Natural Gas	2	1	4	3
Total MWhs	11	10	25	22

Second Quarter of 2014 Compared to Second Quarter of 2013
Reconciliation of Second Quarter of 2013 to Second Quarter of 2014
Net Income from Generation & Marketing
(in millions)

Second Quarter of 2013	$(9)
Changes in Gross Margin:	
Generation	5
Retail, Trading and Marketing	4
Total Change in Gross Margin	9
Changes in Expenses and Other:	
Other Operation and Maintenance	(13)
Asset Impairments and Other Related Charges	154
Depreciation and Amortization	5
Taxes Other Than Income Taxes	4
Interest and Investment Income	(1)
Interest Expense	4
Total Change in Expenses and Other	153
Income Tax Expense	(55)
Second Quarter of 2014	$98

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:

- Gross Margin increased $9 million primarily due to increased market prices in 2014.

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

- Other Operation and Maintenance expenses increased $13 million primarily due to increased plant maintenance expenses.
- Asset Impairments and Other Related Charges decreased by $154 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- Depreciation and Amortization expenses decreased $5 million primarily due to the cessation of depreciation on Muskingum River Plant, Unit 5.
- Income Tax Expense increased $55 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013
Reconciliation of Six Months Ended June 30, 2013 to Six Months Ended June 30, 2014
Net Income from Generation & Marketing
(in millions)

Six Months Ended June 30, 2013	$76	
Changes in Gross Margin:		
Generation	99	
Retail, Trading and Marketing	4	
Total Change in Gross Margin	103	
Changes in Expenses and Other:		
Other Operation and Maintenance	(5	)
Asset Impairments and Other Related Charges	154	
Depreciation and Amortization	10	
Taxes Other Than Income Taxes	8	
Interest Expense	11	
Total Change in Expenses and Other	178	
Income Tax Expense	(96	)
Six Months Ended June 30, 2014	$261	

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:

- Generation increased $99 million primarily due to increased demand and market prices driven by cold temperatures in the first quarter of 2014.

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

- Other Operation and Maintenance expenses increased $5 million primarily due to increased plant maintenance expenses.
- Asset Impairments and Other Related Charges decreased by $154 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- Depreciation and Amortization expenses decreased $10 million primarily due to the cessation of depreciation on Muskingum River Plant, Unit 5.
- Taxes Other Than Income Taxes decreased $8 million primarily due to property taxes related to the 2012 and 2013 plant impairments.
- Interest Expense decreased $11 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense increased $96 million primarily due to an increase in pretax book income.

AEP RIVER OPERATIONS

Second Quarter of 2014 Compared to Second Quarter of 2013

Net Income from our AEP River Operations segment increased from a loss of $9 million in 2013 to income of $3 million in 2014 due to a 45% increase in barge freight revenue for the second quarter of 2014 compared to the second quarter of 2013. The increase in freight revenue is primarily due to improvements in barge freight demand.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Net Income from our AEP River Operations segment increased from a loss of $11 million in 2013 to income of $6 million in 2014 due to a 34% increase in barge freight revenue for 2014 compared to 2013. The additional revenue resulted from improvements in river conditions and increased barge freight demand.

CORPORATE AND OTHER

Second Quarter of 2014 Compared to Second Quarter of 2013

Net Income from Corporate and Other decreased from income of $110 million in 2013 to a loss of $2 million in 2014 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Net Income from Corporate and Other decreased from income of $111 million in 2013 to a loss of $7 million in 2014 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

AEP SYSTEM INCOME TAXES

Second Quarter of 2014 Compared to Second Quarter of 2013

Income Tax Expense increased $147 million primarily due to an increase in pretax book income and a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Income Tax Expense increased $259 million primarily due to an increase in pretax book income and a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

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

	June 30, 2014			December 31, 2013		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$ 18,125	50.1	%	$ 18,377	52.2	%
Short-term Debt	1,482	4.1		757	2.1	

Total Debt	19,607	54.2		19,134	54.3	
AEP Common Equity	16,581	45.8		16,085	45.7	
Noncontrolling Interests	4	—		1	—	
Total Debt and Equity Capitalization	$36,192	100.0	%	$35,220	100.0	%

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Our ratio of debt-to-total capital improved from 54.3% as of December 31, 2013 to 54.2% as of June 30, 2014 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 June 30, 2014, we had $3.5 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-and-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of June 30, 2014, our available liquidity was approximately $2.9 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
Total		3,500	
Cash and Cash Equivalents		190	
Total Liquidity Sources		3,690	
Less:	AEP Commercial Paper Outstanding	732	
	Letters of Credit Issued	49	
Net Available Liquidity		$2,909	

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 six months of 2014 was $877 million. The weighted-average interest rate for our commercial paper during 2014 was 0.26%.

Other Credit Facilities

In January 2014, we issued letters of credit under an $85 million uncommitted facility signed in October 2013. As of June 30, 2014, the maximum future payment for letters of credit issued under the uncommitted facility was $69 million with a maturity in January 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Securitized Accounts Receivable

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased from $700 million and expires in June 2016.

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 credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of June 30, 2014, this contractually-defined percentage was 50.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of June 30, 2014, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our credit agreements.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of June 30, 2014, 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 July 2014. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income primarily 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.

	Six Months Ended June 30,	
	2014	2013
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$118	$279
Net Cash Flows from Operating Activities	2,197	1,516

Net Cash Flows Used for Investing Activities	(2,068)	(1,643)
Net Cash Flows Used for Financing Activities	(57)	(35)
Net Increase (Decrease) in Cash and Cash Equivalents	72	(162)
Cash and Cash Equivalents at End of Period	$190	$117

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

Operating Activities

	Six Months Ended June 30,	
	2014	2013
	(in millions)	
Net Income	$952	$703
Depreciation and Amortization	934	863
Other	311	(50)
Net Cash Flows from Operating Activities	$2,197	$1,516

Net Cash Flows from Operating Activities were $2.2 billion in 2014 consisting primarily of Net Income of $952 million and $934 million of noncash Depreciation and Amortization partially offset by $105 million of fuel cost deferrals and $99 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. The reduction in Fuel, Material and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Net Cash Flows from Operating Activities were $1.5 billion in 2013 consisting primarily of Net Income of $703 million, $863 million of noncash Depreciation and Amortization and $154 million of Asset Impairments related to Muskingum River Plant, Unit 5 partially offset by $102 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.

Investing Activities

	Six Months Ended June 30,	
	2014	2013
	(in millions)	
Construction Expenditures	$(1,883)	$(1,637)
Acquisitions of Nuclear Fuel	(58)	(59)
Acquisitions of Assets/Businesses	(45)	(4)
Insurance Proceeds Related to Cook Plant Fire	—	72
Proceeds from Sales of Assets	2	11
Other	(84)	(26)
Net Cash Flows Used for Investing Activities	$(2,068)	$(1,643)

Net Cash Flows Used for Investing Activities were $2.1 billion in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Net Cash Flows Used for Investing Activities were $1.6 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

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Financing Activities

	Six Months Ended June 30,	
	2014	2013
	(in millions)	
Issuance of Common Stock, Net	$29	$41
Issuance of Debt, Net	459	425
Dividends Paid on Common Stock	(490)	(469)
Other	(55)	(32)
Net Cash Flows Used for Financing Activities	$(57)	$(35)

Net Cash Flows Used for Financing Activities in 2014 were $57 million. Our net debt issuances were $459 million. The net issuances included issuances of $530 million of senior unsecured notes, $304 million of pollution control bonds and $114 million of other debt notes and an increase in short-term borrowing of $725 million offset by retirements of $794 million of senior unsecured and other debt notes, $273 million of pollution control bonds and $138 million of securitization bonds. We paid common stock dividends of $490 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Financing Activities in 2013 were $35 million. Our net debt issuances were $425 million. The net issuances included issuances of $475 million of senior unsecured notes, a $200 million draw on a $1 billion term credit facility, $170 million of pollution control bonds, $101 million of notes payable and an increase in short-term borrowing of $557 million offset by retirements of $796 million of senior unsecured and other debt notes, $131 million of securitization bonds and $146 million of pollution control bonds. We paid common stock dividends of $469 million.

In July 2014, I&M retired $9 million of Notes Payable related to DCC Fuel.

In July 2014, OPCo retired $35 million of Securitization Bonds.

In July 2014, SWEPCo issued a $100 million three-year term credit facility and drew the full amount.

In July 2014, TCC retired $112 million of Securitization Bonds.

BUDGETED CONSTRUCTION EXPENDITURES

In 2014, we increased our forecast for construction expenditures by $350 million to approximately $4.2 billion for 2014. The increase is primarily for transmission investment in the AEP Transmission Holdco, Vertically Integrated Utilities and Transmission and Distribution Utilities segments.

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:

	June 30, 2014	December 31, 2013
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$1,256	$1,330
Railcars Maximum Potential Loss from Lease Agreement	19	19

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 2013 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2013 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 2013 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

Pronouncements Effective in the Future

The FASB issued ASU 2014-08 “Presentation of Financial Statements and Property, Plant and Equipment” changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. We plan to adopt ASU 2014-08 effective January 1, 2015.

The FASB issued ASU 2014-09 "Revenue from Contracts with Customers" clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

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 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.

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QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

Our Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to congestion during the June 2012 - May 2015 Ohio ESP period. Additional risk includes interest rate risk.

Our Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. In addition, our Generation & Marketing segment is also exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, natural gas and coal trading and marketing contracts.

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply, and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC’s 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 AEPSC’s Chief Operating Officer, Chief Financial Officer, and Chief Risk Officer in addition to Energy Supply’s President and Vice President. 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 MTM value as compared to December 31, 2013:
MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2014

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Derivative Contract Net Assets as of December 31, 2013	$32	$3	$157	$192
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(1)	(3)	(25)	(29)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	6	6
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	19	19
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	19	9	—	28
Total MTM Derivative Contract Net Assets as of June 30, 2014	$50	$9	$157	$216
Commodity Cash Flow Hedge Contracts				11
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(2)
Fair Value Hedge Contracts				(5)
Collateral Deposits				(25)
Total MTM Derivative Contract Net Assets as of June 30, 2014				$195

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

Credit Risk

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

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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 June 30, 2014, our credit exposure net of collateral to sub investment grade counterparties was approximately 9.6%, 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 June 30, 2014, 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	$457	$4	$453	2	$228
Split Rating	—	—	—	—	—
Noninvestment Grade	—	—	—	—	—
No External Ratings:					
Internal Investment Grade	65	—	65	4	37
Internal Noninvestment Grade	66	11	55	2	36
Total as of June 30, 2014	$588	$15	$573	8	$301
Total as of December 31, 2013	$787	$18	$769	9	$381

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

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of June 30, 2014, 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

Six Months Ended June 30, 2014				Twelve Months Ended December 31, 2013			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$—	$3	$1	$—	$—	$1	$—	$—

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

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of June 30, 2014 and December 31, 2013, the estimated EaR on our debt portfolio for the following twelve months was $29 million and $32 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2014 and 2013
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
REVENUES				
Vertically Integrated Utilities	$2,236	$2,176	$4,785	$4,532
Transmission and Distribution Utilities	1,064	1,019	2,225	2,109
Generation & Marketing	573	298	1,394	556
Other Revenues	171	89	288	211
TOTAL REVENUES	4,044	3,582	8,692	7,408
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,043	908	2,211	1,939
Purchased Electricity for Resale	473	359	1,111	730
Other Operation	760	664	1,540	1,402
Maintenance	340	285	632	578
Asset Impairments and Other Related Charges	—	154	—	154
Depreciation and Amortization	443	443	934	863
Taxes Other Than Income Taxes	218	222	456	440
TOTAL EXPENSES	3,277	3,035	6,884	6,106
OPERATING INCOME	767	547	1,808	1,302
Other Income (Expense):				
Interest and Investment Income	3	49	4	52
Carrying Costs Income	9	8	15	12
Allowance for Equity Funds Used During Construction	25	17	47	32
Interest Expense	(221)	(228)	(441)	(460)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	583	393	1,433	938
Income Tax Expense	215	68	522	263
Equity Earnings of Unconsolidated Subsidiaries	23	14	41	28
NET INCOME	391	339	952	703
Net Income Attributable to Noncontrolling Interests	1	1	2	2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$390	$338	$950	$701
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	488,291,576	486,293,026	488,080,505	486,059,643

TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.80	$0.69	$1.95	$1.44
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	488,538,227	486,763,615	488,405,869	486,555,121
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.80	$0.69	$1.95	$1.44
CASH DIVIDENDS DECLARED PER SHARE	$0.50	$0.49	$1.00	$0.96

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 44.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2014 and 2013
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net Income	$391	$339	$952	$703
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $1 and $5 for the Three Months Ended June 30, 2014 and 2013, Respectively, and $4 and $8 for the Six Months Ended June 30, 2014 and 2013, Respectively	3	(10)	8	14
Securities Available for Sale, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2014 and 2013, Respectively, and $0 and $0 for the Six Months Ended June 30, 2014 and 2013, Respectively	1	—	1	1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1 and $2 for the Three Months Ended June 30, 2014 and 2013, Respectively, and $1 and $5 for the Six Months Ended June 30, 2014 and 2013, Respectively	1	3	2	9
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	5	(7)	11	24
TOTAL COMPREHENSIVE INCOME	396	332	963	727
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	2	2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$395	$331	$961	$725

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 44.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2014 and 2013
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY - DECEMBER 31, 2012	506	$3,289	$6,049	$6,236	$(337)	$—	$15,237
Issuance of Common Stock	1	7	34				41
Common Stock Dividends				(467)		(2)	(469)
Other Changes in Equity			1				1
Net Income				701		2	703
Other Comprehensive Income					24		24
TOTAL EQUITY - JUNE 30, 2013	507	$3,296	$6,084	$6,470	$(313)	$—	$15,537
TOTAL EQUITY - DECEMBER 31, 2013	508	$3,303	$6,131	$6,766	$(115)	$1	$16,086
Issuance of Common Stock	1	5	24				29
Common Stock Dividends				(488)		(2)	(490)
Other Changes in Equity				(6)		3	(3)
Net Income				950		2	952
Other Comprehensive Income					11		11
TOTAL EQUITY - JUNE 30, 2014	509	$3,308	$6,155	$7,222	$(104)	$4	$16,585

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 44.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2014 and December 31, 2013
(in millions)
(Unaudited)

	June 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$190	$118
Other Temporary Investments (June 30, 2014 and December 31, 2013 Amounts Include $360 and $335, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	377	353
Accounts Receivable:		
Customers	774	746
Accrued Unbilled Revenues	59	157
Pledged Accounts Receivable – AEP Credit	1,060	945
Miscellaneous	60	72
Allowance for Uncollectible Accounts	(27)	(60)
Total Accounts Receivable	1,926	1,860
Fuel	471	701
Materials and Supplies	748	722
Risk Management Assets	146	160
Regulatory Asset for Under-Recovered Fuel Costs	158	80
Margin Deposits	78	70
Prepayments and Other Current Assets	229	246
TOTAL CURRENT ASSETS	4,323	4,310
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,401	25,074
Transmission	11,420	10,893
Distribution	16,716	16,377
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	5,642	5,470
Construction Work in Progress	2,886	2,471
Total Property, Plant and Equipment	62,065	60,285
Accumulated Depreciation and Amortization	19,792	19,288
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	42,273	40,997
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,390	4,376
Securitized Assets	2,244	2,373
Spent Nuclear Fuel and Decommissioning Trusts	2,019	1,932
Goodwill	91	91
Long-term Risk Management Assets	224	297
Deferred Charges and Other Noncurrent Assets	2,056	2,038
TOTAL OTHER NONCURRENT ASSETS	11,024	11,107

TOTAL ASSETS	$57,620	$56,414

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 44.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2014 and December 31, 2013
(dollars in millions)
(Unaudited)

	June 30, 2014	December 31, 2013
CURRENT LIABILITIES		
Accounts Payable	$1,228	$1,266
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	750	700
Other Short-term Debt	732	57
Total Short-term Debt	1,482	757
Long-term Debt Due Within One Year (June 30, 2014 and December 31, 2013 Amounts Include $434 and $416, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,524	1,549
Risk Management Liabilities	60	90
Customer Deposits	306	299
Accrued Taxes	692	822
Accrued Interest	240	245
Regulatory Liability for Over-Recovered Fuel Costs	58	119
Other Current Liabilities	1,010	965
TOTAL CURRENT LIABILITIES	7,600	6,112
NONCURRENT LIABILITIES		
Long-term Debt (June 30, 2014 and December 31, 2013 Amounts Include $2,359 and $2,532, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	15,601	16,828
Long-term Risk Management Liabilities	115	177
Deferred Income Taxes	10,463	10,300
Regulatory Liabilities and Deferred Investment Tax Credits	3,840	3,694
Asset Retirement Obligations	1,908	1,835
Employee Benefits and Pension Obligations	411	415
Deferred Credits and Other Noncurrent Liabilities	1,097	967
TOTAL NONCURRENT LIABILITIES	33,435	34,216
TOTAL LIABILITIES	41,035	40,328
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2014	2013
Shares Authorized	600,000,000	600,000,000

Shares Issued	508,902,340	508,113,964		
(20,336,592 Shares were Held in Treasury as of June 30, 2014 and December 31, 2013)			3,308	3,303
Paid-in Capital			6,155	6,131
Retained Earnings			7,222	6,766
Accumulated Other Comprehensive Income (Loss)			(104)	(115)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			16,581	16,085
Noncontrolling Interests			4	1
TOTAL EQUITY			16,585	16,086
TOTAL LIABILITIES AND EQUITY			$57,620	$56,414

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 44.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2014 and 2013
(in millions)
(Unaudited)

	Six Months Ended June 30,	
	2014	2013
OPERATING ACTIVITIES		
Net Income	$952	$703
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	934	863
Deferred Income Taxes	410	367
Asset Impairments and Other Related Charges	—	154
Carrying Costs Income	(15)	(12)
Allowance for Equity Funds Used During Construction	(47)	(32)
Mark-to-Market of Risk Management Contracts	9	16
Amortization of Nuclear Fuel	79	63
Pension Contributions to Qualified Plan Trust	(71)	—
Property Taxes	92	68
Fuel Over/Under-Recovery, Net	(105)	(4)
Deferral of Ohio Capacity Costs, Net	(99)	(102)
Change in Other Noncurrent Assets	11	(20)
Change in Other Noncurrent Liabilities	132	12
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(73)	(53)
Fuel, Materials and Supplies	207	(61)
Accounts Payable	(39)	(57)
Accrued Taxes, Net	(86)	(214)
Other Current Assets	(3)	(10)
Other Current Liabilities	(91)	(165)
Net Cash Flows from Operating Activities	2,197	1,516
INVESTING ACTIVITIES		
Construction Expenditures	(1,883)	(1,637)
Change in Other Temporary Investments, Net	(24)	38
Purchases of Investment Securities	(510)	(423)
Sales of Investment Securities	483	385
Acquisitions of Nuclear Fuel	(58)	(59)
Acquisitions of Assets/Businesses	(45)	(4)
Insurance Proceeds Related to Cook Plant Fire	—	72
Proceeds from Sales of Assets	2	11
Other Investing Activities	(33)	(26)
Net Cash Flows Used for Investing Activities	(2,068)	(1,643)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	29	41
Issuance of Long-term Debt	939	941
Commercial Paper and Credit Facility Borrowings	—	17
Change in Short-term Debt, Net	725	560

Retirement of Long-term Debt	(1,205)	(1,073)
Commercial Paper and Credit Facility Repayments	—	(20)
Principal Payments for Capital Lease Obligations	(60)	(33)
Dividends Paid on Common Stock	(490)	(469)
Other Financing Activities	5	1
Net Cash Flows Used for Financing Activities	(57)	(35)
Net Increase (Decrease) in Cash and Cash Equivalents	72	(162)
Cash and Cash Equivalents at Beginning of Period	118	279
Cash and Cash Equivalents at End of Period	$190	$117
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$422	$455
Net Cash Paid (Received) for Income Taxes	63	(10)
Noncash Acquisitions Under Capital Leases	33	31
Construction Expenditures Included in Current Liabilities as of June 30,	432	297
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	42	41

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 44.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2013 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 25, 2014.

Revenue Recognition

Electricity Supply and Delivery Activities - Transactions with PJM

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

APCo, I&M and KPCo sell power produced at their generation plants to PJM and purchase power from PJM to supply their retail load. These power sales and purchases for each subsidiary’s retail load are netted hourly for financial reporting purposes. On an hourly net basis, each subsidiary records sales of power to PJM in excess of purchases of power from PJM as revenue on the statements of income. Also, on an hourly net basis, each subsidiary records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale on the statements of income. Upon termination of the Interconnection Agreement in 2014, each subsidiary manages and accounts for its purchases and sales with PJM individually based on market prices.

AEP’s nonregulated subsidiaries also purchase power from PJM and sell power to PJM. With the exception of certain dedicated load bilateral power supply contracts, these transactions are reported as gross purchases and sales.

SPP Integrated Power Market

In March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In the past, PSO and SWEPCo would satisfy their load requirements with their own generation resources or through the Operating Agreement. In the new integrated power market, PSO and SWEPCo operate as standalone entities by offering their respective generation into the SPP power market, which then economically dispatches the resources. This change further enables retail customers to obtain low cost power through either internal generation or power purchases from the SPP market. The new integrated power market now operates in a similar manner as the PJM power market for the AEP East Companies. No significant impact on results of operations is expected due to this change.

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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 June 30,			
	2014		2013	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$390		$338	
Weighted Average Number of Basic Shares Outstanding	488.3	$0.80	486.3	$0.69
Weighted Average Dilutive Effect of:				
Restricted Stock Units	0.2	—	0.5	—
Weighted Average Number of Diluted Shares Outstanding	488.5	$0.80	486.8	$0.69

	Six Months Ended June 30,			
	2014		2013	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$950		$701	
Weighted Average Number of Basic Shares Outstanding	488.1	$1.95	486.1	$1.44
Weighted Average Dilutive Effect of:				
Restricted Stock Units	0.3	—	0.5	—
Weighted Average Number of Diluted Shares Outstanding	488.4	$1.95	486.6	$1.44

There were no antidilutive shares outstanding as of June 30, 2014 and 2013.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

ASU 2014-08 “Presentation of Financial Statements and Property, Plant and Equipment” (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date. Early adoption is permitted for disposals that have not been reported in financial statements previously issued or available for issuance.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. We plan to adopt ASU 2014-08 effective January 1, 2015.

ASU 2014-09 “Revenue from Contracts with Customers” (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. This standard must be retrospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is not permitted. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 30, 2014 and 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 June 30, 2014

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of March 31, 2014	$4	$(22)	$7	$(98)	$(109)
Change in Fair Value Recognized in AOCI	3	—	1	—	4
Amounts Reclassified from AOCI	(1)	1	—	1	1
Net Current Period Other Comprehensive Income	2	1	1	1	5
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 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 March 31, 2013	$12	$(26)	$5	$(297)	$(306)
Change in Fair Value Recognized in AOCI	(8)	(1)	—	—	(9)
Amounts Reclassified from AOCI	(3)	2	—	3	2
Net Current Period Other Comprehensive Income (Loss)	(11)	1	—	3	(7)
Balance in AOCI as of June 30, 2013	$1	$(25)	$5	$(294)	$(313)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	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, 2013	$—	$(23)	$7	$(99)	$(115)
Change in Fair Value Recognized in AOCI	(11)	—	1	—	(10)
Amounts Reclassified from AOCI	17	2	—	2	21
Net Current Period Other Comprehensive Income	6	2	1	2	11
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 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	10	2	1	—	13
Amounts Reclassified from AOCI	(1)	3	—	9	11
Net Current Period Other Comprehensive Income	9	5	1	9	24
Balance in AOCI as of June 30, 2013	$1	$(25)	$5	$(294)	$(313)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 30, 2014 and 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Vertically Integrated Utilities Revenues	$—	$—
Generation & Marketing Revenues	—	(2)
Purchased Electricity for Resale	(2)	(2)
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	—	—
Subtotal - Commodity	(2)	(4)
Interest Rate and Foreign Currency:		
Interest Expense	2	2
Subtotal - Interest Rate and Foreign Currency	2	2
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(2)
Income Tax (Expense) Credit	—	(1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(1)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(5)	(4)
Amortization of Actuarial (Gains)/Losses	7	9
Reclassifications from AOCI, before Income Tax (Expense) Credit	2	5
Income Tax (Expense) Credit	1	2

Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	3
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$1	$2

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Vertically Integrated Utilities Revenues	$—	$—
Generation & Marketing Revenues	—	(5)
Purchased Electricity for Resale	29	4
Property, Plant and Equipment	—	—
Regulatory Assets/(Liabilities), Net (a)	(3)	—
Subtotal - Commodity	26	(1)
Interest Rate and Foreign Currency:		
Interest Expense	4	4
Subtotal - Interest Rate and Foreign Currency	4	4
Reclassifications from AOCI, before Income Tax (Expense) Credit	30	3
Income Tax (Expense) Credit	11	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	19	2
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(10)	(9)
Amortization of Actuarial (Gains)/Losses	14	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	4	14
Income Tax (Expense) Credit	2	5
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2	9
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$21	$11

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

4. RATE MATTERS

As discussed in the 2013 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2013 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 2014 and updates the 2013 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2014	December 31, 2013
	(in millions)	
Regulatory Assets Currently Earning a Return		
Storm Related Costs	$21	$22
Ohio Economic Development Rider	—	14
Other Regulatory Assets Pending Final Regulatory Approval	7	4
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	99	161
IGCC Pre-Construction Costs	21	—
Expanded Net Energy Charge - Coal Inventory	14	21
Mountaineer Carbon Capture and Storage Product Validation Facility	13	13
Ormet Special Rate Recovery Mechanism	10	36
Indiana Under-Recovered Capacity Costs	—	22
Other Regulatory Assets Pending Final Regulatory Approval	34	37
Total Regulatory Assets Pending Final Regulatory Approval	$219	$330

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 Filings

2009 – 2011 ESP

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

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel (OCC) and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 - 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU.

In February 2014, the IEU filed for reconsideration of the Supreme Court of Ohio decision, which was subsequently denied in May 2014. As of June 30, 2014, OPCo's net deferred fuel balance was $411 million, excluding unrecognized equity carrying costs.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues which could reduce OPCo's net deferred fuel balance up to the full amount. These intervenors' appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of June 30, 2014, could reduce carrying costs by $29 million including $15 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. This ruling was generally upheld in rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the 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 OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. As of June 30, 2014, OPCo's incurred deferred capacity costs balance of $396 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

In January and March 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications which included the delay of the energy auctions that were originally ordered in the ESP order. As ordered, in February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. Also as ordered, in May 2014, OPCo conducted an additional energy-only auction for 25% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 25% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. A final audit report is expected in the third quarter of 2014.

Proposed June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. This filing is consistent with the PUCO’s objective for a full transition from FAC and base generation rates to competitively procured SSO supply. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement rider (PPA) that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets. Additionally, in July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the DIR and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014.

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

Significantly Excessive Earnings Test (SEET) Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project. In September 2013, a proposed second phase of OPCo’s gridSMART® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In November 2013, OPCo filed its 2011 and 2012 SEET filings with the PUCO. In March 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. In May 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2012 for OPCo. In May 2014, OPCo filed its 2013 SEET filing with the PUCO. Management does not believe there were significantly excessive earnings in 2013.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo’s generation assets including the transfer of OPCo’s generation assets and associated generation liabilities at net book value to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, corporate separation of OPCo’s generation assets was completed. If any part of the PUCO order is overturned, it could reduce future net income and cash flows and impact financial condition.

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Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates to recover 2012 incremental storm distribution expenses. In April 2014, the PUCO approved a stipulation agreement between OPCo, the PUCO staff and all intervenors, except the OCC, to recover $55 million over a 12-month period. The agreement also provided that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. Compliance tariffs were filed with the PUCO and new rates were implemented in April 2014. In May 2014, the PUCO upheld the settlement agreement on rehearing.

2009 Fuel Adjustment Clause Audit

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

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

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. See the 2009 - 2011 ESP section of the “Ohio Electric Security Plan Filing” related to the PUCO order in the PIRR proceeding. In May 2014, the PUCO issued an order that generally approved OPCo's 2010-2011 fuel costs. The order rejected the auditor recommendation to adjust the WACC carrying charges related to accumulated deferred income taxes. Additionally, the PUCO requested further review related to an affiliate barging agreement and the modification of certain fuel procurement processes and practices. Further, the order provided for the auditor to address any remaining concerns in their next audit report, as they deem necessary. OPCo opposed these additional conditions in its application for rehearing in June 2014. In June 2014, the IEU filed an application with the PUCO for rehearing of this May 2014 order. In July 2014, the PUCO issued an order that denied all requests for rehearing.

2012 and 2013 Fuel Adjustment Clause Audits

In May 2014, the PUCO-selected outside consultant provided its final report related to its 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. These recommendations are opposed by OPCo. In addition, the PUCO will consider the results of the pending audit of the recovery of fixed fuel costs. See the "June 2012 – May 2015 ESP Including Capacity Charge" section above. If the PUCO orders a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware and subsequently shut down operations in October 2013. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider (EDR), 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 EDR. In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommended approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR. Also in February 2014, intervenor comments were filed objecting to full recovery of these foregone revenues. In March 2014, the PUCO issued an order in OPCo's EDR filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of June 30, 2014, is recorded in regulatory assets on the balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

In addition, in the 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

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

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of June 30, 2014, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest.

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

SWEPCo Rate Matters

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of June 30, 2014, the net book value of Welsh Plant, Unit 2 was $85 million, before cost of removal, including materials and supplies inventory and CWIP.

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In March 2014, the PUCT issued an order related to the January 2014 PUCT ruling and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

If any part of the PUCT order is overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs of Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

Texas Transmission Cost Recovery Factor Filing

In May 2014, SWEPCo filed an application with the PUCT to implement its transmission cost recovery factor (TCRF) requesting additional annual revenue of $15 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In July 2014, intervenors filed testimony with recommendations that included decreases ranging from $5 million to $14 million to the requested annual revenue. A hearing at the PUCT is scheduled for August 2014. An order is anticipated in the fourth quarter of 2014. If the PUCT were to disallow any portion of the TCRF, 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. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. 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.

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase to be effective August 2014. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchase power agreement attributable to Louisiana customers. These increases are subject to LPSC staff review. If any of these costs are not recoverable, 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 June 30, 2014, SWEPCo has incurred $72 million in costs related to these projects. SWEPCo will seek to recover these project costs from customers through filings at the state commissions and FERC. These environmental projects could be impacted by pending carbon emission regulations. As of June 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $297 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo and WPCo Rate Matters

Plant Transfer

In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo until APCo's West Virginia base rates are updated. See the "2014 West Virginia Base Rate Case" below. In April 2014, AGR and WPCo filed a request with the FERC for approval to transfer AGR’s one-half interest in the Mitchell Plant to WPCo. In June 2014, the FERC issued an order approving this request. Also in June 2014, an intervenor filed a motion to stay the proceeding at the WVPSC until alternatives to the acquisition of the Mitchell Plant have been explored. In accordance with a July 2014 order addressing the motion to stay, APCo filed supplemental testimony to address intervenor concerns. In July 2014, the WVPSC issued an order that modified the procedural schedule. A hearing at the WVPSC is scheduled for September 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of June 30, 2014, 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. In March 2014, APCo submitted a request to the Virginia SCC as part of the 2014 Virginia Biennial Base Rate Case to amortize the Virginia jurisdictional share of these costs over two years. In June 2014, APCo submitted a request to the WVPSC as part of the 2014 West Virginia Base Rate Case to amortize the West Virginia jurisdictional share of these costs over five years. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Transmission Rate Adjustment Clause (transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually to be effective May 2014. In March 2014, the Virginia SCC issued an order approving a stipulation agreement between APCo and the Virginia SCC staff increasing the transmission RAC revenues by $49 million annually, subject to true-up, effective May 2014. Pursuant to the order, the Virginia SCC staff will audit APCo’s transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo’s next transmission RAC proceeding in 2015.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request a change in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to changes in the expected service lives of various generating units and the extended recovery through 2040 of the net book value of certain planned 2015 plant retirements. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs. A hearing at the Virginia SCC is scheduled for September 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested amortization of $89 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover total vegetation management costs. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

2014 Oklahoma Base Rate Case

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

In April and May 2014, testimony was filed by the OCC staff and intervenors with recommendations that included adjustments to annual base rates ranging from an increase of $16 million to a reduction of $22 million, primarily based upon the determination of depreciation rates and a return on common equity between 9.18% and 9.5%. Additionally, the recommendations did not support the advanced metering rider or the expansion of the transmission rider. In May 2014, PSO filed rebuttal testimony that included an updated annual base rate increase request of $42 million to reflect certain updated costs.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $7 million of revenues in 2014 and increases to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, to be effective November 2014. Further, the stipulation recommends a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring and for riders with an equity component. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. If the OCC were to disallow any portion of this settlement agreement, 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% and adjusted the authorized annual increase in base rates to $92 million in March 2013. In April 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal to the Indiana Supreme Court related to the inclusion of a prepaid pension asset in rate base, which is approximately $7 million in annual revenues. If any part of the IURC order is overturned by the Indiana Supreme Court, it could reduce future net income and cash flows and impact financial condition.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of June 30, 2014, I&M has incurred costs of $439 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC. In May 2014, the IURC issued a final order approving the LCM rider rates that were implemented in 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 the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project.

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

Tanners Creek Plant

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

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant. I&M requested to have the impact of these new depreciation rates incorporated into the rates set in its next rate case where I&M will also seek continued recovery of a return on the net book value of the Tanners Creek Plant. The new depreciation rates would result in a decrease in I&M's Michigan jurisdictional electric depreciation expense which I&M proposed to implement the month following a MPSC order. A hearing at the MPSC is scheduled for September 2014.

As of June 30, 2014, the net book value of the Tanners Creek Plant was $327 million, before cost of removal, including materials and supplies inventory and CWIP. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

Plant Transfer

In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of June 30, 2014, the net book value of Big Sandy Plant, Unit 2 was $276 million, before cost of removal, including materials and supplies inventory and CWIP.

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

In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2013 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 June 30, 2014, the maximum future payments for letters of credit issued under the revolving credit facilities were $49 million with maturities ranging from August 2014 to June 2015.

In January 2014, we issued letters of credit under an $85 million uncommitted facility signed in October 2013. As of June 30, 2014, the maximum future payment for letters of credit issued under the uncommitted facility was $69 million with a maturity in January 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $477 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $483 million. The letters of credit have maturities ranging from March 2015 to July 2017.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of June 30, 2014, SWEPCo has collected approximately $63 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $47 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 certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. As of June 30, 2014, 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 June 30, 2014, the maximum potential loss for these lease agreements was approximately $21 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 assignments are 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 $12 million and $14 million for I&M and SWEPCo, respectively, for the remaining railcars as of June 30, 2014.

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

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

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

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $7 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 generation 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.

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation

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

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. Defendants in these cases, including AEP, previously filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. In June 2014, AEP filed a petition with the U.S. Supreme Court seeking review of the personal jurisdiction issue. In July 2014, the U.S. Supreme Court granted the defendants' previously filed petition for further review with the U.S. Supreme Court on the preemption issue. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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Wage and Hours Lawsuit

In August 2013, PSO received an amended complaint filed in the U.S. District Court for the Northern District of Oklahoma by 36 current and former line and warehouse employees alleging that they have been denied overtime pay in violation of the Fair Labor Standards Act. Plaintiffs claim that they are entitled to overtime pay for “on call” time. They allege that restrictions placed on them during on call hours are burdensome enough that they are entitled to compensation for these hours as hours worked. Plaintiffs also filed a motion to conditionally certify this action as a class action, claiming there are an additional 70 individuals similarly situated to plaintiffs. Plaintiffs seek damages in the amount of unpaid overtime over a three-year period and liquidated damages in the same amount.

In March 2014, the federal court granted plaintiffs’ motion to conditionally certify the action as a class action. Notice was given to all class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. We will continue to defend the case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

National Do Not Call Registry Lawsuit

In May 2014, AEP Energy was served with a complaint filed in the U.S. District Court for the Northern District of Illinois, alleging violations of the Telephone Consumer Protection Act (TCPA). The plaintiff alleges that he received telemarketing calls on behalf of AEP Energy despite having registered his telephone number on the National Do Not Call Registry. Plaintiff seeks to represent a class of persons who allegedly received such calls. Plaintiff seeks statutory damages under the TCPA on behalf of himself and the alleged class as well as injunctive relief. We will continue to defend this case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

6. IMPAIRMENT

2013

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

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

7. 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 six months ended June 30, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Service Cost	$18	$18	$3	$6
Interest Cost	56	51	17	17
Expected Return on Plan Assets	(65)	(70)	(28)	(26)
Amortization of Prior Service Credit	—	—	(17)	(18)
Amortization of Net Actuarial Loss	31	46	6	16
Net Periodic Benefit Cost (Credit)	$40	$45	$(19)	$(5)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Service Cost	$36	$35	$7	$12
Interest Cost	111	101	34	35
Expected Return on Plan Assets	(131)	(139)	(56)	(53)
Amortization of Prior Service Cost (Credit)	1	1	(34)	(35)
Amortization of Net Actuarial Loss	62	92	11	32
Net Periodic Benefit Cost (Credit)	$79	$90	$(38)	$(9)

8. BUSINESS SEGMENTS

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

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy to serve standard service offer customers, and provides capacity for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

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

The tables below present our reportable segment information for the three and six months ended June 30, 2014 and 2013 and balance sheet information as of June 30, 2014 and December 31, 2013. These amounts include certain estimates and allocations where necessary.

	Vertically Integrated Utilities		Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing		AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)										
Three Months Ended June 30, 2014											
Revenues from:											
External Customers	$2,236	(b)	$ 1,064	$ 21	$573	(b)	$ 140	$10	$ —	(c)	$ 4,044
Other Operating Segments	16	(b)	70	36	340	(b)	20	12	(494)		—
Total Revenues	$2,252		$ 1,134	$ 57	$913		$ 160	$22	$ (494)		$ 4,044
Net Income (Loss)	$155		$ 90	$ 47	$98		$ 3	$(2)	$ —		$ 391

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
Three Months Ended June 30, 2013									
Revenues from:									
External Customers	$2,176	$ 1,019	$ 6	$298	$ 111	$9	$ (37)	(c)	$ 3,582
Other Operating Segments	126	45	13	594	6	12	(796)		—
Total Revenues	$2,302	$ 1,064	$ 19	$892	$ 117	$21	$ (833)		$ 3,582
Net Income (Loss)	$153	$ 75	$ 19	$(9)	$(9)	$110	$ —		$ 339

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Six Months Ended June 30, 2014								
Revenues from:								
External Customers	$4,785 (b)	$ 2,225	$ 33	$ 1,394 (b)	$ 286	$ 20	$ (51) (c)	$ 8,692
Other Operating Segments	53 (b)	124	52	770 (b)	39	28	(1,066)	—
Total Revenues	$4,838	$ 2,349	$ 85	$ 2,164	$ 325	$ 48	$ (1,117)	$ 8,692
Net Income (Loss)	$434	$ 187	$ 71	$ 261	$ 6	$ (7)	$ —	$ 952

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Six Months Ended June 30, 2013								
Revenues from:								
External Customers	$4,532	$ 2,109	$ 9	$ 556	$ 239	$ 14	$ (51) (c)	$ 7,408
Other Operating Segments	285	89	18	1,256	11	25	(1,684)	—
Total Revenues	$4,817	$ 2,198	$ 27	$ 1,812	$ 250	$ 39	$ (1,735)	$ 7,408
Net Income (Loss)	$334	$ 162	$ 31	$ 76	$ (11)	$ 111	$ —	$ 703

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
June 30, 2014									
Total Property, Plant and Equipment	$38,390	$ 12,554	$ 2,079	$ 8,345	$ 640	$ 329	$ (272	) (d)	$ 62,065
Accumulated Depreciation and Amortization	12,562	3,407	16	3,514	204	181	(92	) (d)	19,792
Total Property Plant and Equipment - Net	$25,828	$ 9,147	$ 2,063	$ 4,831	$ 436	$ 148	$ (180	) (d)	$ 42,273
Total Assets	$33,024	$ 13,859	$ 2,702	$ 6,301	$ 638	$ 20,379	$ (19,283	) (d) (e)	$ 57,620
Long-term Debt Due Within One Year:									
Affiliated	$ 131	$ —	$ —	$ 125	$ —	$—	$ (256	)	$ —
Non-Affiliated	1,382	448	—	687	3	4	—		2,524
Long-term Debt:									
Affiliated	20	—	—	32	—	—	(52	)	—
Non-Affiliated	8,445	5,306	689	239	82	840	—		15,601
Total Long-term Debt	$9,978	$ 5,754	$ 689	$ 1,083	$ 85	$ 844	$ (308	)	$ 18,125

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
December 31, 2013									
Total Property, Plant and Equipment	$37,545	$ 12,143	$ 1,636	$ 8,277	$ 638	$ 315	$ (269	) (d)	$ 60,285
Accumulated Depreciation	12,250	3,342	10	3,409	189	173	(85	) (d)	19,288

and Amortization									
Total Property Plant and Equipment - Net	$25,295	$ 8,801	$ 1,626	$4,868	$449	$142	$(184	) (d)	$ 40,997
Total Assets	$32,791	$ 14,165	$ 2,245	$6,426	$673	$19,645	$(19,531	) (d) (e)	$ 56,414
Long-term Debt Due Within One Year:									
Affiliated	$—	$ —	$ —	$179	$5	$—	$(184	)	$ —
Non-Affiliated	720	697	—	126	2	4	—		1,549
Long-term Debt:									
Affiliated	151	—	—	118	10	—	(279	)	—
Non-Affiliated	9,265	5,360	620	664	83	836	—		16,828
Total Long-term Debt	$10,136	$ 6,057	$ 620	$1,087	$100	$840	$(463	)	$ 18,377

(a) Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

(b) Includes the impact of the corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.

(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation.

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

(e) 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.

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9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

The following table represents the gross notional volume of our outstanding derivative contracts as of June 30, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume June 30, 2014 (in millions)	December 31, 2013	Unit of Measure
Commodity:			
Power	430	406	MWhs
Coal	3	4	Tons
Natural Gas	116	127	MMBtus
Heating Oil and Gasoline	5	6	Gallons
Interest Rate	$176	$191	USD
Interest Rate and Foreign Currency	$819	$820	USD

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

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014. During the three and six months ended June 30, 2013, we designated financial heating oil and gasoline derivatives as cash flow hedges. For disclosure purposes, these contracts were included with other hedging activities as “Commodity” as of December 31, 2013. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. 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 June 30, 2014 and December 31, 2013 condensed balance sheets, we netted $26 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1 million and $13 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 June 30, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
June 30, 2014

	Risk Management Contracts	Hedging Contracts		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)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in millions)					
Current Risk Management Assets	$454	$28	$4	$486	$(340)	$ 146
Long-term Risk Management Assets	314	5	—	319	(95)	224
Total Assets	768	33	4	805	(435)	370
Current Risk Management Liabilities	372	20	1	393	(333)	60
Long-term Risk Management Liabilities	182	2	10	194	(79)	115
Total Liabilities	554	22	11	587	(412)	175
Total MTM Derivative Contract Net Assets (Liabilities)	$214	$11	$(7)	$218	$(23)	$ 195

Fair Value of Derivative Instruments
December 31, 2013

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk	Gross Amounts Offset in	Net Amounts of Assets/Liabilities Presented in the

Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Management Assets/ Liabilities Recognized	the Statement of Financial Position (b)	Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$347	$12	$4	$363	$(203)	$ 160
Long-term Risk Management Assets	368	3	—	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$186	$1	$(12)	$175	$15	$ 190

(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 six months ended June 30, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2014 and 2013

	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2014	2013	2014	2013
	(in millions)			
Vertically Integrated Utilities Revenues	$4	$4	$22	$10
Generation & Marketing Revenues	16	17	48	33
Regulatory Assets (a)	—	(8)	—	(6)
Regulatory Liabilities (a)	29	4	118	(2)
Total Gain on Risk Management Contracts	$49	$17	$188	$35

(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 six months ended June 30, 2014, we recognized gains of $2 million and $4 million, respectively, on our hedging instruments and offsetting losses of $2 million and $4 million, respectively, on our long-term debt. During the three and six months ended June 30, 2013, we recognized losses of $11 million and $12 million, respectively, on our hedging instruments and offsetting gains of $11 million and $12 million, respectively, on our long-term debt. During the three and six months ended June 30, 2014 and 2013, 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 six months ended June 30, 2014 and 2013, 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 six months ended June 30, 2013, we designated heating oil and gasoline derivatives as cash flow hedges. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014.

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 six months ended June 30, 2014 and 2013, 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 six months ended June 30, 2014 and 2013, we did not designate any foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2014 and 2013, 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 six months ended June 30, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of June 30, 2014 and December 31, 2013 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2014

	Commodity	Interest Rate and Foreign Currency	Total
	(in millions)		
Hedging Assets (a)	$15	$—	$15
Hedging Liabilities (a)	4	2	6
AOCI Gain (Loss) Net of Tax	6	(21)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	4	(3)	1

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

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

(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 June 30, 2014, 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 42 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), a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, and guaranties for contractual obligations, we are obligated to post an additional amount of collateral if our credit ratings decline below a specified rating threshold. 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 a specified rating threshold that would require the posting of additional collateral. 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 and guaranties for contractual obligations if our credit ratings had declined below a specified rating threshold and (c) how much was attributable to RTO and ISO activities as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$1	$3
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	167	33
Amount Attributable to RTO and ISO Activities	54	28

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 June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$201	$293
Amount of Cash Collateral Posted	—	1
Additional Settlement Liability if Cross Default Provision is Triggered	141	235

10. 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. 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 AEPSC's 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 AEPSC's Chief Operating Officer, Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President.

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 June 30, 2014 and December 31, 2013 are summarized in the following table:

	June 30, 2014		December 31, 2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$18,125	$20,284	$18,377	$19,672

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:

	June 30, 2014			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$272	$—	$—	$272
Fixed Income Securities - Mutual Funds	80	—	—	80
Equity Securities - Mutual Funds	13	12	—	25
Total Other Temporary Investments	$365	$12	$—	$377

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

(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 six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Proceeds from Investment Sales	$—	$—	$—	$—
Purchases of Investments	—	—	1	11
Gross Realized Gains on Investment Sales	—	—	—	—
Gross Realized Losses on Investment Sales	—	—	—	—

As of June 30, 2014 and December 31, 2013, we had no Other Temporary Investments with an unrealized loss position. As of June 30, 2014, 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 six months ended June 30, 2014 and 2013, see Note 3.

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 June 30, 2014 and December 31, 2013:

	June 30, 2014			December 31, 2013		
	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	$—	$—	$19	$—	$—
Fixed Income Securities:						
United States Government	580	37	(26)	609	26	(4)
Corporate Debt	47	4	(1)	37	2	(1)
State and Local Government	309	1	(1)	255	1	—
Subtotal Fixed Income Securities	936	42	(28)	901	29	(5)
Equity Securities - Domestic	1,068	557	(79)	1,012	506	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$2,019	$599	$(107)	$1,932	$535	$(87)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Proceeds from Investment Sales	$335	$217	$483	$385
Purchases of Investments	345	227	509	412
Gross Realized Gains on Investment Sales	9	9	17	12
Gross Realized Losses on Investment Sales	8	8	9	10

The adjusted cost of fixed income securities was $894 million and $872 million as of June 30, 2014 and December 31, 2013, respectively. The adjusted cost of equity securities was $511 million and $506 million as of June 30, 2014 and December 31, 2013, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2014 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$39
1 year – 5 years	414
5 years – 10 years	208
After 10 years	275
Total	$936

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 June 30, 2014 and December 31, 2013. 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
June 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$15	$1	$—	$174	$190
Other Temporary Investments					
Restricted Cash (a)	251	10	—	11	272
Fixed Income Securities - Mutual Funds	80	—	—	—	80
Equity Securities - Mutual Funds (b)	25	—	—	—	25
Total Other Temporary Investments	356	10	—	11	377
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	15	585	148	(399)	349
Cash Flow Hedges:					