AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 23, 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 September 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 October 23, 2014
American Electric Power Company, Inc.	489,240,481 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 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 electric system, owned and operated by AEP 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 II 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 nine months ended September 30, 2014 were up 32% in our western region and 20% in our eastern region while cooling degree days were down 7% for the same period in both the eastern and western regions. Our weather-normalized retail sales volumes for the third quarter of 2014 increased by 0.1% from their levels for the third quarter of 2013 and increased by 0.4% for the first nine months of 2014 from their levels for the first nine months of 2013. In comparison to 2013, our industrial sales volume increased 1.2% for the three months ended September 30, 2014 and decreased 0.7% for the nine months ended September 30, 2014. The decrease in industrial sales volume is due mainly to the closure of Ormet, a large aluminum company. Excluding Ormet, our nine months ended September 30, 2014 industrial sales volumes increased 3.8% over the nine months ended September 30, 2013.

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 September 30, 2014, OPCo's net deferred fuel balance was $395 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 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 September 30, 2014, OPCo's incurred deferred capacity costs balance was $409 million, including debt carrying costs.

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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 and September 2014, OPCo conducted energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions 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. In October 2014, the independent auditor filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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.

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. 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 capacity and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement (PPA) rider 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. 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. 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 October 2014, OPCo filed a separate application with the PUCO to propose a new PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, its deferred capacity cost and its proposed PPA rider, 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 certain parts of the PUCT order are 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.

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 increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also 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. An order is anticipated in the fourth quarter of 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.

In August 2014, the Virginia SCC staff and intervenors filed testimony concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their recommended adjustments, was above the allowed threshold. Recommendations included (a) refunds to customers ranging from $15 million to $22 million, (b) the write-off of certain APCo assets, including IGCC pre-construction costs and previously approved 2009 storm costs, totaling $27 million and (c) $38 million in increased depreciation expense annually, retroactive to January 1, 2014, primarily related to accelerating depreciation on APCo generation assets to be retired in the second quarter of 2015. Hearings at the Virginia SCC were held in September 2014. A decision is expected in November 2014. 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.

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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 recovery 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 vegetation management costs, including a return on capital investment. In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included the extension of the intervention period to November 2014 and a delay in the implementation of new rates from April 2015 to May 2015. Hearings at the WVPSC are scheduled for January 2015. 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.

Plant Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. 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. In June 2014, the FERC issued an order approving AGR and WPCo's request to transfer AGR’s one-half interest in the Mitchell Plant to WPCo.

In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding $20 million of certain assets, which will be paid by WPCo and recovered as a regulatory asset over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant’s output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is approved for inclusion in rates. Management anticipates an order related to the proposed plant transfer will be issued in the fourth quarter of 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “Plant Transfer” section of APCo Rate Matters in Note 4.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. An intervenor has requested and received a revised procedural schedule to determine if the allocation of fuel costs has been applied appropriately. In October 2014, intervenors filed testimony that recommended the KPSC direct KPCo to modify its fuel allocation methodology and order a refund to customers of approximately $13 million, plus carrying charges at a weighted average cost of capital, related to the period January 1, 2014 through April 30, 2014. A hearing at the KPSC is scheduled for November 2014. Management believes the methodology used to determine fuel costs is appropriate and intends to oppose the recommendations filed by intervenors. If the KPSC directs KPCo to modify its fuel allocation methodology, it could affect the allocation of costs for all periods beginning January 2014, and if any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “Kentucky Fuel Adjustment Clause Review” 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.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of September 30, 2014, SWEPCo has incurred costs of $112 million and has contractual construction obligations of $84 million 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 adversely impacted by pending carbon emission regulations. See "CO_2 Regulation" section of "Environmental Issues" below. As of September 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $335 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.

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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, proposed clean water rules and renewal permits for certain water discharges that are currently under appeal.

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.

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Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 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 the 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 both regulated and 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 September 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 $973 million.

In addition, we are in the process of obtaining permits following the KPSC's approval for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas. As of September 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

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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 and impact financial condition.

Clean Air Act Requirements

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

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. 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.

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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 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. Industry and environmental groups filed petitions for further review in the U.S. Supreme Court.

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

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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 guidelines use a “portfolio” approach to reducing emissions from existing sources that includes 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 Federal EPA issued proposed guidelines establishing state goals for CO_2 emissions from existing EGUs and comments are due December 1, 2014. The Federal EPA also issued proposed regulations governing emissions of CO_2 from modified and reconstructed EGUs in June 2014 and comments are due in October 2014. 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. Petitions for review of the final rule have been filed by industry and environmental groups and have been consolidated in the U.S. Court of Appeals for the Fourth Circuit.

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. Comments are due in October 2014.

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 transport liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Vertically Integrated Utilities	$219	$173	$651	$505
Transmission and Distribution Utilities	92	119	279	281
AEP Transmission Holdco	43	22	114	53
Generation & Marketing	117	112	378	188
AEP River Operations	11	(1)	17	(12)
Corporate and Other (a)	11	8	4	119
Earnings Attributable to AEP Common Shareholders	$493	$433	$1,443	$1,134

(a) While not considered a reportable segment, Corporate and Other primarily includes 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.

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Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders increased from $433 million in 2013 to $493 million in 2014 primarily due to:

- Impairments during the third quarter of 2013 related to the following:
- A decision by the PUCT determining that AFUDC on the Turk Plant was included in the Texas capital cost cap.
- A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- Successful rate proceedings in our various jurisdictions.
- An increase in transmission investment which resulted in higher revenues and income.

These increases were partially offset by:

- A decrease in weather-related usage.
- An increase in plant maintenance.
- An increase in vegetation management expenses.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders increased from $1.1 billion in 2013 to $1.4 billion in 2014 primarily due to:

- Impairments during 2013 related to the following:
- Muskingum River Plant, Unit 5.
- A decision by the PUCT determining that AFUDC on the Turk Plant was included in the Texas capital cost cap.
- A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- Successful rate proceedings in our various jurisdictions.
- A net increase in weather-related usage.
- Higher market prices and increased sales volumes.
- An increase in transmission investment which resulted in higher revenues and income.

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.
- An increase in depreciation expense due to increased investments.
- An increase in vegetation management expenses.
- An increase in plant maintenance.

Our results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
	(in millions)			
Revenues	$2,450	$2,738	$7,288	$7,555
Fuel and Purchased Electricity	1,010	1,325	3,038	3,590
Gross Margin	1,440	1,413	4,250	3,965
Other Operation and Maintenance	615	524	1,809	1,653
Asset Impairments and Other Related Charges	—	144	—	144
Depreciation and Amortization	257	233	772	702
Taxes Other Than Income Taxes	95	93	278	277
Operating Income	473	419	1,391	1,189
Interest and Investment Income	2	—	3	7
Carrying Costs Income	1	5	2	10
Allowance for Equity Funds Used During Construction	12	9	33	27
Interest Expense	(133)	(136)	(396)	(408)
Income Before Income Tax Expense and Equity Earnings	355	297	1,033	825
Income Tax Expense	135	123	380	318
Equity Earnings of Unconsolidated Subsidiaries	—	—	1	1
Net Income	220	174	654	508
Net Income Attributable to Noncontrolling Interests	1	1	3	3
Earnings Attributable to AEP Common Shareholders	$219	$173	$651	$505

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2014	2013		Nine Months Ended September 30, 2014	2013	
	(in millions of KWhs)					
Retail:						
Residential	8,505	9,043		26,126	25,710	
Commercial	6,743	6,910		18,980	18,913	
Industrial	8,962	8,634		26,319	25,602	
Miscellaneous	608	602		1,740	1,717	
Total Retail	24,818	25,189		73,165	71,942	
Wholesale (a)	8,632	NM	(b)	27,418	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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Eastern Region				
Actual – Heating (a)	2	1	2,248	1,854
Normal – Heating (b)	5	6	1,736	1,741
Actual – Cooling (c)	559	657	921	1,007
Normal – Cooling (b)	733	733	1,062	1,062
Western Region				
Actual – Heating (a)	—	—	1,233	1,009
Normal – Heating (b)	1	2	921	923
Actual – Cooling (c)	1,246	1,387	1,926	2,070
Normal – Cooling (b)	1,399	1,396	2,109	2,106

(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.

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Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2013	$ 173
Changes in Gross Margin:	
Retail Margins	23
Off-system Sales	15
Transmission Revenues	1
Other Revenues	(12)
Total Change in Gross Margin	27
Changes in Expenses and Other:	
Other Operation and Maintenance	(91)
Asset Impairments and Other Related Charges	144
Depreciation and Amortization	(24)
Taxes Other Than Income Taxes	(2)
Interest and Investment Income	2
Carrying Costs Income	(4)
Allowance for Equity Funds Used During Construction	3
Interest Expense	3
Total Change in Expenses and Other	31
Income Tax Expense	(12)
Third Quarter of 2014	$ 219

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

- Retail Margins increased $23 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories which include:
    - APCo - $43 million.
    - KPCo - $14 million.

  For the rate increases described above, $35 million of these increases relate to riders/trackers which have corresponding increases in expense items below.

  These increases were partially offset by:
  - A $36 million decrease in weather-related usage primarily due to a decrease in cooling degree days.
- Margins from Off-system Sales increased $15 million primarily due to changes in margin sharing.
- Other Revenues decreased $12 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 effective December 31, 2013 as a result of corporate separation in Ohio. This decrease in RTD revenue has 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 $91 million primarily due to the following:
  - A $19 million increase in plant outage and maintenance expenses.
  - A $17 million increase in recoverable expenses, including PJM expenses, currently fully recovered in rate recovery riders/trackers partially offset by RTD expenses for barging activities.
  - A $17 million increase in employee-related expenses.
  - An $11 million increase in transmission and distribution expenses primarily due to storms and non-recoverable SPP services.
  - A $10 million increase in uncollectible accounts primarily due to the favorable resolution of contingencies related to pole attachments in the third quarter of 2013.
  - A $9 million increase in approved incremental vegetation management expenses.
  - An $8 million increase due to an accrual for expected environmental remediation costs.
- Asset Impairments and Other Related Charges decreased $144 million primarily due to the following:
  - A $111 million decrease due to the third quarter 2013 write-off of AFUDC on the Turk Plant.
  - A $33 million decrease due to KPCo's third quarter 2013 write-off of scrubber costs on the Big Sandy Plant and other generation in accordance with the KPSC's October 2013 order.
- Depreciation and Amortization expenses increased $24 million primarily due to overall higher depreciable base.
- Income Tax Expense increased $12 million primarily due to an increase in pretax book income partially offset by other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2013	$505	
Changes in Gross Margin:		
Retail Margins	186	
Off-system Sales	121	
Transmission Revenues	17	
Other Revenues	(39	)
Total Change in Gross Margin	285	
Changes in Expenses and Other:		
Other Operation and Maintenance	(156	)
Asset Impairments and Other Related Charges	144	
Depreciation and Amortization	(70	)
Taxes Other Than Income Taxes	(1	)
Interest and Investment Income	(4	)
Carrying Costs Income	(8	)
Allowance for Equity Funds Used During Construction	6	
Interest Expense	12	
Total Change in Expenses and Other	(77	)
Income Tax Expense	(62	)
Nine Months Ended September 30, 2014	$651	

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 $186 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories which include:
    - APCo - $114 million.
    - KPCo - $41 million.
    - SWEPCo - $28 million.
    - I&M - $28 million.

    For the rate increases described above, $87 million of these increases relate to riders/trackers which have corresponding increases in expense items below.
  - A $16 million increase due to favorable weather conditions.

  These increases were partially offset by:
  - A $39 million increase in PJM expenses net of recovery or offsets.
- Margins from Off-system Sales increased $121 million primarily due to higher market prices.
- Transmission Revenues increased $17 million primarily due to increased investment in the PJM region.
- Other Revenues decreased $39 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 as of December 31, 2013 as a result of corporate separation in Ohio. This decrease in RTD revenue has a corresponding 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 $156 million primarily due to the following:
- A $38 million increase in recoverable expenses, including PJM expenses, currently fully recovered in rate recovery riders/trackers partially offset by RTD expenses for barging activities.
- A $38 million increase in transmission expenses primarily related to PJM and SPP services.
- A $29 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 $20 million increase in employee-related expenses.
- A $14 million increase in distribution and transmission vegetation management 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.
- Asset Impairments and Other Related Charges decreased $144 million primarily due to the following:
- A $111 million decrease due to the third quarter 2013 write-off of AFUDC on the Turk Plant.
- A $33 million decrease due to KPCo's third quarter 2013 write-off of scrubber costs on the Big Sandy Plant and other generation in accordance with the KPSC's October 2013 order.
- Depreciation and Amortization expenses increased $70 million primarily due to overall higher depreciable base.
- Carrying Cost Income decreased $8 million primarily due to the November 2013 securitization of the West Virginia ENEC deferral balance.
- Allowance for Equity Funds Used During Construction increased $6 million primarily due to an increase in environmental construction projects.
- Interest Expense decreased $12 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 as well as an increase in the debt component of AFUDC due to increased transmission and environmental projects.
- Income Tax Expense increased $62 million primarily due to an increase in pretax book income.

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TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(in millions)			
Revenues	$1,231	$1,195	$3,580	$3,393
Fuel and Purchased Electricity	377	406	1,123	1,260
Amortization of Generation Deferrals	27	—	83	—
Gross Margin	827	789	2,374	2,133
Other Operation and Maintenance	329	254	920	717
Depreciation and Amortization	182	165	499	449
Taxes Other Than Income Taxes	117	118	344	327
Operating Income	199	252	611	640
Interest and Investment Income	3	—	9	1
Carrying Costs Income	6	3	20	10
Allowance for Equity Funds Used During Construction	3	2	8	4
Interest Expense	(68)	(72)	(210)	(219)
Income Before Income Tax Expense	143	185	438	436
Income Tax Expense	51	66	159	155
Net Income	92	119	279	281
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$92	$119	$279	$281

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	
	(in millions of KWhs)					
Retail:						
Residential	7,194	7,371		20,280	19,589	
Commercial	6,796	6,827		19,012	18,693	
Industrial	5,489	5,648		16,262	17,277	
Miscellaneous	187	195		540	535	
Total Retail (a)	19,666	20,041		56,094	56,094	
Wholesale (b)	575	NM	(c)	1,727	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.

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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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Eastern Region				
Actual – Heating (a)	1	1	2,540	2,165
Normal – Heating (b)	7	8	2,074	2,083
Actual – Cooling (c)	581	645	943	991
Normal – Cooling (b)	663	660	946	940
Western Region				
Actual – Heating (a)	—	—	302	143
Normal – Heating (b)	—	—	200	205
Actual – Cooling (d)	1,367	1,387	2,309	2,464
Normal – Cooling (b)	1,346	1,339	2,358	2,346

(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.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2013	$119
Changes in Gross Margin:	
Retail Margins	25
Transmission Revenues	12
Other Revenues	1
Total Change in Gross Margin	38
Changes in Expenses and Other:	
Other Operation and Maintenance	(75)
Depreciation and Amortization	(17)
Taxes Other Than Income Taxes	1
Interest and Investment Income	3
Carrying Costs Income	3
Allowance for Equity Funds Used During Construction	1
Interest Expense	4
Total Change in Expenses and Other	(80)
Income Tax Expense	15
Third Quarter of 2014	$92

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 $25 million primarily due to the following:
- A $23 million increase in TCC and TNC revenues primarily due to increased transmission investment in Texas as well as increased usage.
- A $2 million increase in revenues primarily associated with Ohio rate riders/trackers and PJM revenues, partially offset by regulatory provisions. These increases have corresponding increases in expense items discussed below.
- Transmission Revenues increased $12 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. This increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.

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

- Other Operation and Maintenance expenses increased $75 million primarily due to the following:
  - A $74 million increase in expenses, including PJM expenses and the Ohio storm amortization, currently fully recovered in rate recovery riders/trackers.
  - A $9 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $7 million decrease in transmission expenses primarily related to PJM services.
- Depreciation and Amortization expenses increased $17 million primarily due to the following:
  - A $9 million increase in amortization related to TCC and OPCo securitizations, which are offset in Retail Margins above.
  - An $8 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Interest Expense decreased $4 million primarily due to reduced long-term debt outstanding.
- Income Tax Expense decreased $15 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2013	$281
Changes in Gross Margin:	
Retail Margins	172
Transmission Revenues	59
Other Revenues	10
Total Change in Gross Margin	241
Changes in Expenses and Other:	
Other Operation and Maintenance	(203)
Depreciation and Amortization	(50)
Taxes Other Than Income Taxes	(17)
Interest and Investment Income	8
Carrying Costs Income	10
Allowance for Equity Funds Used During Construction	4
Interest Expense	9
Total Change in Expenses and Other	(239)
Income Tax Expense	(4)
Nine Months Ended September 30, 2014	$279

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 $172 million primarily due to the following:
- A $101 million increase in revenues primarily associated with Ohio rate riders/trackers and PJM revenues, partially offset by regulatory provisions. These increases have corresponding increases in expense items discussed below.
- A $71 million increase in TCC and TNC revenues primarily due to increased transmission investment in Texas as well as increased usage.
- Transmission Revenues increased $59 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. This increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.
- Other Revenues increased $10 million primarily due to an increase in Texas securitization revenues which is offset in Depreciation and Amortization below. This increase is also partially offset by a $4 million demand side management bonus recorded in 2013.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $203 million primarily due to the following:
  - A $150 million increase in recoverable expenses, including PJM expenses and the Ohio storm amortization, currently fully recovered in rate recovery riders/trackers.
  - A $19 million increase in expenses related to various distribution services and vegetation management.
  - A $14 million increase in remitted Universal Service Fund (USF) surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase has corresponding increases in Retail Margins above.
  - An $11 million increase in employee-related expenses.
  - A $7 million increase in storm-related expenses primarily in OPCo's service territory.
- Depreciation and Amortization expenses increased $50 million primarily due to the following:
  - A $32 million increase in amortization related to TCC and OPCo securitizations, which are offset in Retail Margins.
  - An $18 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $17 million primarily due to increased property taxes.
- Interest and Investment Income increased $8 million primarily due to interest on affiliated notes resulting from corporate separation.
- Carrying Costs Income increased $10 million primarily due to increased capacity deferral carrying charges.
- Interest Expense decreased $9 million primarily due to reduced long-term debt outstanding.

AEP TRANSMISSION HOLDCO

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders from our AEP Transmission Holdco segment increased from $22 million in 2013 to $43 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders from our AEP Transmission Holdco segment increased from $53 million in 2013 to $114 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT. During this period, net plant increased from $1.3 billion to $2.4 billion.

GENERATION & MARKETING

	Three Months Ended September 30,		Nine Months Ended September 30,	
Generation & Marketing	2014	2013	2014	2013
	(in millions)			
Revenues	$901	$1,001	$3,065	$2,813
Fuel, Purchased Electricity and Other	529	648	1,894	1,764
Gross Margin	372	353	1,171	1,049
Other Operation and Maintenance	122	106	363	342
Asset Impairments and Other Related Charges	—	—	—	154
Depreciation and Amortization	56	57	169	180
Taxes Other Than Income Taxes	12	11	37	44
Operating Income	182	179	602	329
Interest and Investment Income	2	—	4	2
Interest Expense	(12)	(10)	(35)	(44)
Income Before Income Tax Expense	172	169	571	287
Income Tax Expense	55	57	193	99
Net Income	117	112	378	188
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$117	$112	$378	$188

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of MWhs)			
Fuel Type:				
Coal	16	10	37	29
Natural Gas	2	2	6	5
Total MWhs	18	12	43	34

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2013	$112	
Changes in Gross Margin:		
Generation	19	
Total Change in Gross Margin	19	
Changes in Expenses and Other:		
Other Operation and Maintenance	(16	)
Depreciation and Amortization	1	
Taxes Other Than Income Taxes	(1	)
Interest and Investment Income	2	
Interest Expense	(2	)
Total Change in Expenses and Other	(16	)
Income Tax Expense	2	
Third Quarter of 2014	$117	

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 $19 million primarily due to lower fuel expenses.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $16 million primarily due to an increase in plant maintenance.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2013	$188
Changes in Gross Margin:	
Generation	118
Retail, Trading and Marketing	4
Total Change in Gross Margin	122
Changes in Expenses and Other:	
Other Operation and Maintenance	(21)
Asset Impairments and Other Related Charges	154
Depreciation and Amortization	11
Taxes Other Than Income Taxes	7
Interest and Investment Income	2
Interest Expense	9
Total Change in Expenses and Other	162
Income Tax Expense	(94)
Nine Months Ended September 30, 2014	$378

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 $118 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 $21 million primarily due to increased plant maintenance.
- 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 $11 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- Taxes Other Than Income Taxes decreased $7 million primarily due to a decrease in property taxes related to the 2012 and 2013 plant impairments.
- Interest Expense decreased $9 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense increased $94 million primarily due to an increase in pretax book income.

AEP RIVER OPERATIONS

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from a loss of $1 million in 2013 to income of $11 million in 2014 due to a 20% increase in barge freight revenue for the third quarter of 2014 compared to the third quarter of 2013. The increase in freight revenue is primarily due to improvements in barge freight demand.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from a loss of $12 million in 2013 to income of $17 million in 2014 due to a 30% 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

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from $8 million in 2013 to $11 million in 2014 primarily due to the recording of federal and state income tax adjustments in the third quarter of 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $119 million in 2013 to $4 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

Third Quarter of 2014 Compared to Third Quarter of 2013

Income Tax Expense increased $12 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments in the third quarter of 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Income Tax Expense increased $271 million primarily due to an increase in pretax book income and by 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

	September 30, 2014			December 31, 2013		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$18,058	49.9	%	$18,377	52.2	%
Short-term Debt	1,282	3.5		757	2.1	
Total Debt	19,340	53.4		19,134	54.3	
AEP Common Equity	16,868	46.6		16,085	45.7	
Noncontrolling Interests	4	—		1	—	
Total Debt and Equity Capitalization	$36,212	100.0	%	$35,220	100.0	%

Our ratio of debt-to-total capital improved from 54.3% as of December 31, 2013 to 53.4% as of September 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 September 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 September 30, 2014, our available liquidity was approximately $3.1 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
	Revolving Credit Facility	$1,750	June 2016
	Revolving Credit Facility	1,750	July 2017
Total		3,500	
Cash and Cash Equivalents		194	
Total Liquidity Sources		3,694	
Less:	AEP Commercial Paper Outstanding	532	
	Letters of Credit Issued	76	
Net Available Liquidity		$3,086	

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

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first nine months of 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 September 30, 2014, the maximum future payment for letters of credit issued under the uncommitted facility was $78 million with maturity dates through 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 September 30, 2014, this contractually-defined percentage was 49.9%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of September 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 September 30, 2014, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.53 per share in October 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.

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$118	$279
Net Cash Flows from Operating Activities	3,725	3,040
Net Cash Flows Used for Investing Activities	(3,081)	(2,520)
Net Cash Flows Used for Financing Activities	(568)	(652)
Net Increase (Decrease) in Cash and Cash Equivalents	76	(132)
Cash and Cash Equivalents at End of Period	$194	$147

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

Operating Activities

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Net Income	$1,446	$1,137
Depreciation and Amortization	1,441	1,310
Other	838	593
Net Cash Flows from Operating Activities	$3,725	$3,040

Net Cash Flows from Operating Activities were $3.7 billion in 2014 consisting primarily of Net Income of $1.4 billion and $1.4 billion of noncash Depreciation and Amortization partially offset by $106 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 $3 billion in 2013 consisting primarily of Net Income of $1.1 billion, and $1.3 billion of noncash Depreciation and Amortization and $298 million of Asset Impairments related to Muskingum River Plant, Unit 5, Turk and Big Sandy Plants, partially offset by $157 million of Ohio capacity deferrals as a result of the PUCO's July 2012 approval of a capacity deferral mechanism. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax/book temporary differences from operations. Net cash flows for Accrued Taxes were a result of recording the estimated federal tax loss associated with tax/book temporary differences and the recognition of the tax benefit related to the U.K. Windfall Tax.

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Investing Activities

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Construction Expenditures	$(2,899)	$(2,481)
Acquisitions of Nuclear Fuel	(109)	(110)
Acquisitions of Assets/Businesses	(45)	(6)
Insurance Proceeds Related to Cook Plant Fire	—	72
Proceeds from Sales of Assets	2	14
Other	(30)	(9)
Net Cash Flows Used for Investing Activities	$(3,081)	$(2,520)

Net Cash Flows Used for Investing Activities were $3.1 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 $2.5 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Issuance of Common Stock, Net	$63	$61
Issuance of Debt, Net	193	43
Dividends Paid on Common Stock	(736)	(709)
Other	(88)	(47)
Net Cash Flows Used for Financing Activities	$(568)	$(652)

Net Cash Flows Used for Financing Activities in 2014 were $568 million. Our net debt issuances were $193 million. The net issuances included issuances of $650 million of senior unsecured notes, $343 million of pollution control bonds and $224 million of other debt notes and an increase in short-term borrowing of $525 million offset by retirements of $953 million of senior unsecured and other debt notes, $312 million of pollution control bonds and $273 million of securitization bonds. We paid common stock dividends of $736 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 $652 million. Our net debt issuances were $43 million. The net issuances included issuances of $475 million of senior unsecured notes, $800 million draws on a $1 billion term credit facility, $305 million of pollution control bonds, $267 million of securitization bonds, $251 million of notes payable and other debt and an increase in short-term borrowing of $237 million offset by retirements of $1.8 billion of senior unsecured and other debt notes, $211 million of securitization bonds and $281 million of pollution control bonds. We paid common stock dividends of $709 million.

In October 2014, APCo remarketed $100 million of Pollution Control Bonds due in 2018 at 1.625%.

In October 2014, I&M retired $5 million of Notes Payable related to DCC Fuel.

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:

	September 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 with early adoption permitted.

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.

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)
Nine Months Ended September 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	(7)	(3)	(32)	(42)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	9	9
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	21	21
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	12	8	—	20
Total MTM Derivative Contract Net Assets as of September 30, 2014	$37	$8	$155	$200
Commodity Cash Flow Hedge Contracts				6
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(1)
Fair Value Hedge Contracts				(8)
Collateral Deposits				(14)
Total MTM Derivative Contract Net Assets as of September 30, 2014				$183

(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 September 30, 2014, our credit exposure net of collateral to sub investment grade counterparties was approximately 9.3%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of September 30, 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	$482	$1	$481	2	$245
Split Rating	14	—	14	1	13
Noninvestment Grade	2	1	1	2	1
No External Ratings:					
Internal Investment Grade	71	—	71	4	44
Internal Noninvestment Grade	71	14	57	1	29
Total as of September 30, 2014	$640	$16	$624	10	$332
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 September 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

Nine Months Ended September 30, 2014				Twelve Months Ended December 31, 2013			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$—							