AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 28, 2016

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 March 31, 2016
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 April 28, 2016
American Electric Power Company, Inc.	491,313,380 ($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
March 31, 2016

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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and 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 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.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment.
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.
APSC	Arkansas Public Service Commission.
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.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel IV LLC, DCC Fuel VI LLC, DCC Fuel VII LLC and DCC Fuel VIII 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.

ETT	Electric Transmission Texas, LLC, an equity interest joint venture between Parent and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.

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Term	Meaning
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.
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.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Power Purchase and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, 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.

Term	Meaning
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.
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.
TRA	Tennessee Regulatory Authority.
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 the Registrants 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 2015 Annual Report, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “ “would,” “project,” “continue” and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes 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 AEP service territories.

Inflationary or deflationary interest rate trends.

Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.

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 competition, including competition for retail customers.

Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.

The cost of fuel and its transportation and the creditworthiness and performance of fuel suppliers and transporters.

Availability of necessary generation capacity and the performance of generation plants.

The ability to recover fuel and other energy costs through regulated or competitive electric rates.

The ability to build transmission lines and facilities (including the 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 that could impact the continued operation, cost recovery and/or profitability of 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.

The ability to constrain operation and maintenance costs.

The ability to develop and execute a strategy based on a view regarding prices of electricity and gas.

Prices and demand for power generated and sold at wholesale.

Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.

The 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 and capacity auction returns.

Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

The market for generation in Ohio and PJM and the ability to recover investments in Ohio generation assets.
The ability to successfully and profitably manage competitive generation assets, including the evaluation of strategic alternatives for these assets as some of the alternatives could result in a loss.
Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of debt.

The impact of volatility in the capital markets on the value of the investments held by the 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 the Registrants speak only as of the date of this report or as of the date they are made. The Registrants 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 2015 Annual Report and in Part II of this report.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP’s website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP’s website is not part 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

AEP's weather-normalized retail sales volumes for the first quarter of 2016 decreased by 0.1% from the first quarter of 2015. AEP's first quarter 2016 industrial sales increased 0.9% compared to the first quarter of 2015 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized residential and commercial sales decreased 1.6% and increased 0.7% in the first quarter of 2016, respectively, from the first quarter of 2015.

Ohio PPA Application

In December 2015, a contested stipulation agreement related to the PPA rider application was filed with the PUCO. The stipulation agreement provided for a 10.38% return on common equity, for AGR, with the PPA rider term extending through May 2024. The stipulation agreement included (a) an affiliate PPA between OPCo and AGR to be included in the PPA rider, (b) OPCo's OVEC contractual entitlement to be included in the PPA rider, (c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider, (d) annual compliance reviews before the PUCO, (e) an agreement to retire, refuel or repower to 100% natural gas, Conesville Plant, Units 5 and 6 and Cardinal Plant, Unit 1 by 2029 and 2030, respectively, and (f) a commitment by OPCo to submit an amended ESP filing by April 30, 2016 which would extend all ESP riders through May 2024. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MW and a wind energy project(s) of at least 500 MW, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. OPCo agreed to file a carbon reduction plan with the PUCO by December 2016 that will focus on fuel diversification and carbon emission reductions.

In March 2016, the PUCO modified and approved the stipulation agreement. The PPA is effective April 2016 through May 2024, with quarterly PPA rider reconciliations to actual PPA costs compared to PJM market revenues, subject to audit and review by the PUCO. PUCO modifications to the stipulation agreement included (a) a temporary customer-specific rate impact cap of 5% through May 2018, (b) a directive that OPCo will not seek recovery from customers for any costs associated with the retirement, refueling, co-firing or repowering of PPA units, (c) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider, (d) the right for the PUCO to exclude costs associated with a forced outage lasting longer than 90 days, (e) the limitation that OPCo will not flow through any net costs or revenues associated with AGR's obligations or entitlements related to Cardinal Plant, Units 2 and 3 and (f) the right for the PUCO to re-evaluate or modify the PPA rider if there is a change to PJM's tariffs or rules that prohibits the PPA units from being bid into PJM auctions.

The PUCO order did not modify OPCo's agreement to provide potential additional customer credits of up to $100 million during the final four years of the PPA rider, which are shown in the following table:

PJM Planning Year	Potential Credit
June 2020 through May 2021	$10 million
June 2021 through May 2022	$20 million
June 2022 through May 2023	$30 million
June 2023 through May 2024	$40 million

In accordance with accounting guidance for “Contingencies,” management will perform ongoing reviews of projected PPA plant costs compared to related market prices for energy and capacity to determine if additional credits to customers are probable. Management is unable to determine a range of potential losses that are reasonably possible of occurring. Potential PPA credits could reduce future net income and cash flows and impact financial condition.

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In January 2016, a complaint was filed at the FERC against AGR and OPCo requesting that FERC review the PPA under its standards for affiliate transactions. In March 2016, a group of merchant generation owners filed a complaint at the FERC against PJM seeking revisions to the Minimum Offer Price Rule (MOPR) in PJM's tariff. The complaint against PJM requested the FERC act in advance of the May 2016 Base Residual Auction for the 2019/2020 delivery year. If approved as proposed, the revised MOPR would apply to the PPA units and could affect bidding into PJM.

In April 2016, the FERC issued an order granting the January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo are required to submit the affiliate PPA to the FERC for review in accordance with FERC's rules governing affiliate transactions. The affiliate PPA is not effective until the FERC review is completed and the affiliate PPA is approved. Management is evaluating its alternatives in response to this order.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filings" section of Note 4.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In 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. In June 2015, the Supreme Court of Ohio issued a decision that reversed, as requested by OPCo, the PUCO order on the carrying cost rate issue. In October 2015 this matter was remanded back to the PUCO for reinstatement of the weighted average cost of capital (WACC) rate. A decision from the PUCO is pending.

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 established base generation rates through May 2015. In 2013, this ruling was generally upheld in PUCO rehearing orders.

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 included reserve margins, was approximately $34/MW day through May 2014 and $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 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. In April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. In May 2015, the PUCO granted intervenors requests for rehearing. As of March 31, 2016, OPCo's net deferred capacity costs balance was $320 million, including debt carrying costs. Through March 31, 2016, OPCo has collected $266 million in deferred capacity costs, and related carrying charges.

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

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In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. 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.

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 October 2014, the independent auditor, selected by the PUCO, filed its report with the PUCO for the period August 2012 through May 2015. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88/MW day capacity charge, the independent auditor has recommended 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 disagrees with the findings in the audit report.

In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo's capacity charges. The Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo's authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period. The PUCO reduced OPCo's authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo's arguments that the $147.41/MW day credit was overstated by approximately $100.00/MW day due to various inaccuracies affecting input data and assumptions.

The Supreme Court of Ohio also rejected a portion of OPCo's RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to apply these RSR revenues against OPCo's deferred capacity costs. The Supreme Court of Ohio was not able to determine the amount of the reduction to OPCo's deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction.

Due to the interrelated nature of these two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, management believes that the PUCO will rule upon both issues together. Further, management believes that the net impact of these issues will largely offset and will not result in a material future reduction of OPCo's net income.

Additionally, the Supreme Court of Ohio agreed with OPCo's cross-appeal assertion that the 12% threshold was not based on a comparison of OPCo's return on equity to the returns during the same period of comparable publicly traded companies, including utilities, that face comparable business and financial risk. The Supreme Court of Ohio reversed the 12% threshold and remanded this issue to the PUCO.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filings" section of Note 4.

Merchant Fleet Alternatives

AEP is evaluating strategic alternatives for AGR's merchant generation fleet, included in the Generation & Marketing segment, as well as AEGCo's Lawrenceburg Plant, all of which operate in PJM. Potential alternatives may include, but are not limited to, continued ownership of the merchant generation fleet or a sale of the merchant generation fleet. Management has not made a decision regarding the potential alternatives, nor have they set a specific time frame for a decision. These alternatives could result in a loss which could reduce future net income and cash flows and impact financial condition.

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Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC’s grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana, and through SWEPCo’s wholesale customers under FERC-based rates.

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased SWEPCo’s 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 would review base rates in 2014 and 2015 and that SWEPCo would recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for November 2016. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition. See the “2012 Louisiana Formula Rate Filing” section of Note 4.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could cost approximately $900 million, excluding AFUDC. As part of this investment, 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 $400 million, excluding AFUDC. As of March 31, 2016, SWEPCo had incurred costs of $372 million, including AFUDC, and had remaining contractual construction obligations of $28 million related to these projects. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. SWEPCo will seek recovery of the remaining project costs from customers at the state commissions and the FERC. See “Mercury and Other Hazardous Air Pollutants (HAPs) Regulation” and “Climate Change, CO_2 Regulation and Energy Policy” sections of “Environmental Issues” below. Management continues to evaluate the impact of environmental rules and related project cost estimates.

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As of March 31, 2016, the net book value of Welsh Plant, Units 1 and 3 was $606 million, before cost of removal, including materials and supplies inventory and CWIP. As of March 31, 2016, the net book value of Welsh Plant, Unit 2 was $84 million, before cost of removal, including materials and supplies inventory and CWIP. Welsh Plant, Unit 2 was considered probable of abandonment and was retired in April 2016.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense, (b) a rider or base rate increase of $44 million to recover costs for environmental controls and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% effective in January 2016. The proposed $44 million increase related to environmental investments was effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed in service.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO’s investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, some intervenors recommended no change in depreciation rates for Northeastern Plant, Units 3 and 4. These units are currently being depreciated through 2040. Hearings at the OCC were held in December 2015. In January 2016, PSO implemented an interim annual base rate increase of $75 million, subject to refund pending a final order from the OCC. An order from the OCC is anticipated by the end of the third quarter of 2016. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2015 Oklahoma Base Rate Case” section of Note 4.

2016 West Virginia Expanded Net Energy Charge Filing

In March 2016, APCo and WPCo filed their combined annual ENEC filing with the WVPSC which requested an increase in ENEC rates of $108 million to be effective July 2016. The increase primarily relates to recovery of the December 2015 under-recovered ENEC deferral balance and the recovery of costs associated with the continuation and expansion of certain transmission and generation construction projects. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

TCC and TNC Distribution Cost Recovery Factor (DCRF) Filings

In April 2016, TCC and TNC filed separate requests with the PUCT for approval of DCRF riders to allow recovery of eligible net distribution investments. TCC’s and TNC’s requests included revenue requirements of $54 million and $16 million, respectively, both to be effective September 2016. Amounts approved would be subject to refund based upon a prudence review of the investments in TCC's and TNC's next base rate cases.

If any of these costs are not recoverable, it could reduce TCC and TNC's respective future net income and cash flows and impact financial condition.

Kingsport Base Rate Case

In January 2016, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66%. New rates are expected to be implemented in the third quarter of 2016. A hearing at the TRA is scheduled for August 2016. If KGPCo does not recover its costs, it could reduce future net income and cash flows and impact financial condition.

Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo's existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo's next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The amendments provide that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In February 2016, APCo filed a motion to stay the Virginia SCC's consideration of the petition due to a pending appeal at the Supreme Court of Virginia by industrial customers of a non-related utility regarding the constitutionality of the amendments. APCo and other parties have filed their responses to the petition. Oral arguments at the Virginia SCC were held in March 2016. Management is unable to predict the outcome of these challenges. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

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 delivery year.

Through May 2015, AGR provided generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo paid AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo paid 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. As of June 2015, AGR's generation resources are compensated through the PJM capacity auction. Shown below are the RPM results through the June 2017 through May 2018 period:

PJM Auction Period	PJM Auction Price (per MW day)
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

In June 2015, FERC approved PJM's proposal to create a new Capacity Performance (CP) product, intended to improve generator performance and reliability during emergency events by allowing higher offers into the RPM auction and imposing greater charges for non-performance during emergency events. PJM will procure approximately 80% CP and 20% Base Capacity for the June 2018 through May 2019 and June 2019 through May 2020 periods, while transitioning to 100% CP with the June 2020 through May 2021 period. FERC also approved transition incremental auctions to procure CP for the June 2016 through May 2017 and June 2017 through May 2018 periods.

In the third quarter of 2015, PJM conducted the two transition auctions. The transition auctions allowed generators, including AGR, to re-offer cleared capacity that qualifies as CP. Shown below are the results of the two transition auctions:

PJM Auction Period	Capacity Performance Transition Incremental Auction Price (per MW day)
June 2016 through May 2017	$ 134.00
June 2017 through May 2018	151.50

AGR cleared 7,169 MW at $134/MW-day for the June 2016 through May 2017 period, replacing the original auction clearing price of $59.37/MW-day. AGR cleared 6,495 MW for the June 2017 through May 2018 period at $151.50/MW-day, replacing the original auction clearing price of $120/MW-day.

In August 2015, PJM held its first base residual auction implementing CP rules for the June 2018 through May 2019 period. PJM cleared approximately 81% of the capacity for the June 2018 through May 2019 period as CP and 19% as Base Capacity. AGR cleared 7,209 MW at the CP auction price of $164.77/MW-day. Shown below are the results for the June 2018 through May 2019 period:

PJM Auction Period	Capacity Performance Auction Price (per MW day)	Base Capacity Auction Price (per MW day)
June 2018 through May 2019	$ 164.77	$ 150.00

The FERC order exempted Fixed Resource Requirement entities, including APCo, I&M, KPCo and WPCo, from the CP rules through the delivery period ending May 2019. In July 2015, AEP filed a request seeking rehearing of the FERC order approving CP. AEP is awaiting an order on its request for rehearing and will continue to advocate for further improvements to the CP rules and the capacity market as a whole through the PJM stakeholder process.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on the 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 2015 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 a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiff's claims. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing.

In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of the other remaining claims with prejudice and the court subsequently entered a final judgment. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP is implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. Additional investments and operational changes will need to be made in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM, CO_2 and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, rules governing the beneficial use and disposal of coal combustion products, clean water rules and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. AEP, along with various industry groups, affected states and other parties challenged some of the Federal EPA requirements in court. Management is also engaged in the development of possible future requirements including the items discussed below and state plans to reduce CO_2 emissions to address concerns about global climate change. Management believes 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 2015 Annual Report. AEP 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 AEP is unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of March 31, 2016, the AEP System had a total generating capacity of approximately 32,000 MWs, of which approximately 18,000 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP's investment to meet these proposed requirements ranges from approximately \$3.2 billion to \$3.8 billion through 2025. These amounts include investments to convert some of the coal generation to natural gas.

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 the 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, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and nonregulated plants.

In May 2015, AEP retired the following plants or units of plants:

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
Total		5,535

As of March 31, 2016, the net book value of the AGR units listed above was zero. The net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the regulated plants in the table above was approved for recovery, except for $148 million which management plans to seek regulatory approval.

In April 2016, AEP retired the following units of plants:

Company	Plant Name and Unit	Generating Capacity (in MWs)
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		998

As of March 31, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the PSO and SWEPCo units listed above was $178 million. For Northeastern Station, Unit 4, PSO is seeking regulatory recovery of remaining net book values. For Welsh Plant, Unit 2, management will seek regulatory recovery of remaining net book values.

In October 2015, KPCo obtained permits following the KPSC's approval to convert its 278 MW Big Sandy Plant, Unit 1 to natural gas. Management expects to begin operations as a natural gas unit in the second quarter of 2016. As of March 31, 2016, the net book value, before cost of removal, including related materials and supplies inventory and CWIP balances of Big Sandy Plant, Unit 1 was $110 million.

APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert its 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In the third and fourth quarters of 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the retired coal related assets for Clinch River Plant, Units 1 and 2, management plans to seek regulatory approval for $24 million. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively. As of March 31, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of Clinch River Plant, Units 1 and 2 was $155 million.

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.

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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. 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 and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA. All of the states in which AEP's power plants are located are covered by CSAPR. 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, but the rule was remanded to the Federal EPA upon further review and remains in effect. 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) will 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 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. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls currently under construction. 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 July 2015, management submitted comments to the proposed Arkansas FIP and participated in comments filed by industry associations of which AEP is a member. Management supports compliance with CSAPR programs as satisfaction of the BART requirements.

The Federal EPA issued rules for CO_2 emissions that apply to new and existing electric utility units. See "Climate Change, CO_2 Regulation and Energy Policy" section below.

The Federal EPA also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 and ozone. In October 2015, the Federal EPA announced a lower final NAAQS for ozone of 70 parts per billion. 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 facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

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

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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. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing 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. A petition for 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 Federal EPA 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. The court granted the Federal EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In December 2015, the Federal EPA issued a proposal to revise the ozone season NO_x budgets in 23 states beginning in 2017 to address transport issues associated with the 2008 ozone standard and the budget errors identified in the U.S. Court of Appeals for the District of Columbia Circuit's July 2015 decision. The proposal was open for public comment through February 1, 2016. Management believes that the Federal EPA mistakenly relied on future projected retirements and failed to take into account actual operating experience when establishing the 2017 budgets. Management also believes there is insufficient time to implement the required reductions.

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 units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). 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 was required within three years. Management 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.

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 trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule for further proceedings consistent with the U.S. Supreme Court's decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Management submitted comments on the proposal and will continue to monitor future regulatory developments. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. The rule remains in effect.

Climate Change, CO_2 Regulation and Energy Policy

The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. Management is taking steps to comply with these requirements, including increasing wind power purchases and broadening the AEP System's portfolio of energy efficiency programs.

In October 2015, the Federal EPA published the final standards for new, modified and reconstructed fossil fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources. The final standard for new combustion turbines is 1,000 pounds of CO_2 per MWh and the final standard for new fossil steam units is 1,400 pounds of CO_2 per MWh. Reconstructed turbines are subject to the same standard as new units and no standard for modified combustion turbines was issued. Reconstructed fossil steam units are subject to a standard of 1,800 pounds of CO_2 per MWh for larger units and 2,000 pounds of CO_2 per MWh for smaller units. Modified fossil steam units will be subject to a site specific standard no lower than the standards that would be applied if the units were reconstructed.

The final emissions guidelines for existing sources, known as the Clean Power Plan, are based on a series of declining emission rates that are implemented beginning in 2022 through 2029. The final emission rate is 771 pounds of CO_2 per MWh for existing natural gas combined cycle units and 1,305 pounds of CO_2 per MWh for existing fossil steam units in 2030 and thereafter. The Federal EPA also developed a set of rate-based and mass-based state goals.

The Federal EPA also published proposed “model” rules that can be adopted by the states that would allow sources within “trading ready” state programs to trade, bank or sell allowances or credits issued by the states. These rules would also be the basis for any federal plan issued by the Federal EPA in a state that fails to submit or receive approval for a state plan. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. States are required to submit final plans or an extension request by September 2016 to the Federal EPA. States receiving an extension request must submit final plans by September 2018. Management is evaluating the rules impact as well as the anticipated actions by states where assets are located. The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. The Federal EPA established a 90-day public comment period on the proposed rules and management submitted comments.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force AEP to close some coal-fired facilities and could lead to possible impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants.

The final rule became effective in October 2015. The Federal EPA will regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements. The rule does not apply to inactive CCR landfills and inactive surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice and internet posting requirements. The CCR rule requirements contain a compliance schedule spanning an approximate four year implementation period. If CCR units do not meet these standards within the timeframes provided, they will be required to close. Extensions of time for closure are available provided there is no alternative disposal capacity or the owner can certify cessation of a boiler by a certain date. Challenges to the rule by industry associations of which AEP is a member are proceeding. In April 2016, the parties entered into a settlement agreement that would require the Federal EPA to reconsider certain aspects of the rule. If approved, under the settlement agreement, the provisions creating specific closure requirements will be vacated for inactive impoundments that complete closure by April 17, 2018. The Federal EPA will propose a rule to extend the deadlines for these facilities to comply with the CCR standards promptly and attempt to finalize that rule within four months. The Federal EPA will also use its best efforts to complete reconsideration of all of the affected provisions within three years.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented. Management recorded a $95 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Management will continue to evaluate the rule's impact on operations.

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 AEP's 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. Encapsulated beneficial uses are not materially impacted by the new rule but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule 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 were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In addition to other requirements, the final rule establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. The applicability of these requirements is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. Management will continue to review the final rule in detail to evaluate whether the plants are currently meeting the proposed limitations, what technologies are incorporated into AEP's long-range plans and what additional costs might be incurred. Management is assessing technology additions and retrofits.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This jurisdictional definition applies 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. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a "significant nexus." Management believes that clarity and efficiency in the permitting process is needed. Management remains concerned that the rule introduces new concepts and could subject more of AEP’s operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. Challengers include industry associations of which AEP is a member. The U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule pending jurisdictional determinations. In February 2016, the U.S. Court of Appeals for the Sixth Circuit issued a decision holding that it has exclusive jurisdiction to decide the challenges to the “waters of the United States” rule. Industry, state and related associations, including an association in which AEP is a member, have filed petitions for a rehearing of the jurisdictional decision.

RESULTS OF OPERATIONS

SEGMENTS

AEP’s primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its 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.

AEP’s reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

The remainder of AEP’s activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See “AEPRO (Corporate and Other)” section of Note 6 for additional information.

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The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three months ended March 31, 2016 and 2015.

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Vertically Integrated Utilities	$277.6	$299.3
Transmission and Distribution Utilities	108.0	97.2
AEP Transmission Holdco	43.9	35.8
Generation & Marketing	70.7	187.4
Corporate and Other	1.0	9.5
Earnings Attributable to AEP Common Shareholders	$501.2	$629.2

AEP CONSOLIDATED

First Quarter of 2016 Compared to First Quarter of 2015

Earnings Attributable to AEP Common Shareholders decreased from $629 million in 2015 to $501 million in 2016 primarily due to:

- A decrease in generation revenues due to lower capacity revenue and a decrease in wholesale energy prices.
- A decrease in weather-related usage.
- Reduced trading and marketing activity as compared to 2015.
- A decrease in off-system sales margins due to lower market prices, reduced sales volumes and losses from a power contract with OVEC.

These decreases were partially offset by:

- A decrease in system income taxes due to lower pretax book income.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.
- An increase in weather-normalized sales.

AEP's results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended March 31, 2016	2015
	(in millions)	
Revenues	$2,245.6	$2,505.1
Fuel and Purchased Electricity	742.0	983.2
Gross Margin	1,503.6	1,521.9
Other Operation and Maintenance	629.6	575.4
Depreciation and Amortization	266.8	272.2
Taxes Other Than Income Taxes	97.9	96.9
Operating Income	509.3	577.4
Interest and Investment Income	0.6	0.5
Carrying Costs Income	2.2	1.9
Allowance for Equity Funds Used During Construction	14.8	14.1
Interest Expense	(127.3)	(130.6)
Income Before Income Tax Expense and Equity Earnings	399.6	463.3
Income Tax Expense	121.9	163.6
Equity Earnings of Unconsolidated Subsidiaries	1.0	0.6
Net Income	278.7	300.3
Net Income Attributable to Noncontrolling Interests	1.1	1.0
Earnings Attributable to AEP Common Shareholders	$277.6	$299.3

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2016	2015
	(in millions of KWhs)	
Retail:		
Residential	9,124	10,379
Commercial	5,880	6,011
Industrial	8,267	8,360
Miscellaneous	541	548
Total Retail	23,812	25,298
Wholesale (a)	4,792	8,268
Total KWhs	28,604	33,566

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

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 the eastern region have a larger effect on revenues than changes in the 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 March 31,	
	2016	2015
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,520	2,045
Normal – Heating (b)	1,633	1,604
Actual – Cooling (c)	5	—
Normal – Cooling (b)	5	5
Western Region		
Actual – Heating (a)	678	1,040
Normal – Heating (b)	892	877
Actual – Cooling (c)	30	14
Normal – Cooling (b)	23	23

(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) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

First Quarter of 2015	$299.3
Changes in Gross Margin:	
Retail Margins	8.9
Off-system Sales	(17.5)
Transmission Revenues	(11.6)
Other Revenues	1.9
Total Change in Gross Margin	(18.3)
Changes in Expenses and Other:	
Other Operation and Maintenance	(54.2)
Depreciation and Amortization	5.4
Taxes Other Than Income Taxes	(1.0)
Interest and Investment Income	0.1
Carrying Costs Income	0.3
Allowance for Equity Funds Used During Construction	0.7
Interest Expense	3.3
Total Change in Expenses and Other	(45.4)
Income Tax Expense	41.7
Equity Earnings	0.4
Net Income Attributable to Noncontrolling Interests	(0.1)
First Quarter of 2016	$277.6

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

- Retail Margins increased $9 million primarily due to the following:
- The effect of successful rate proceedings in AEP’s service territories which included:
- A $27 million increase primarily due to increases in rates in West Virginia and Virginia, offset by a prior year adjustment due to the amended Virginia Law impacting biennial reviews.
- A $17 million increase for KPCo primarily due to increases in base rates and riders.
- A $6 million increase for I&M primarily due to rate increases from annual FERC formula rate adjustments and Indiana rate riders.
- A $4 million increase for PSO primarily due to interim base rate increases.

For the rate increases described above, $39 million relate to riders/trackers which have corresponding increases in expense items below.

- A $28 million increase in weather-normalized margins primarily in the residential and commercial classes.
- A $9 million decrease in Fuel and Purchased Electricity due to the transfer of a one-half interest in the Mitchell Plant from AGR to WPCo in January 2015. This decrease was partially offset by increases in other expense items below.

These increases were partially offset by:

- An $83 million decrease in weather-related usage.
- Margins from Off-system Sales decreased $18 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $12 million primarily due to lower Network Integration Transmission Service revenues.

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

- Other Operation and Maintenance expenses increased $54 million primarily due to the following:
  - A $22 million increase in employee-related expenses.
  - A $14 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $12 million increase in recoverable expenses, primarily including vegetation management and storm expenses currently fully recovered in rate recovery riders/trackers.
  - A $6 million increase due to the reduction of an environmental liability in 2015 at I&M.
- Depreciation and Amortization expenses decreased $5 million primarily due to the impact of plant retirements in 2015 for APCo, I&M and KPCo.
- Income Tax Expense decreased $42 million primarily due to a decrease in pretax book income and by the recording of federal and state income tax adjustments.

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TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended March 31, 2016	2015
	(in millions)	
Revenues	$1,096.8	$1,270.1
Purchased Electricity	217.6	420.8
Amortization of Generation Deferrals	55.1	31.4
Gross Margin	824.1	817.9
Other Operation and Maintenance	324.4	319.3
Depreciation and Amortization	156.3	167.7
Taxes Other Than Income Taxes	123.3	122.2
Operating Income	220.1	208.7
Interest and Investment Income	2.2	1.9
Carrying Costs Income	1.9	6.5
Allowance for Equity Funds Used During Construction	4.3	3.7
Interest Expense	(67.2)	(69.6)
Income Before Income Tax Expense	161.3	151.2
Income Tax Expense	53.3	54.0
Net Income	108.0	97.2
Net Income Attributable to Noncontrolling Interests	—	—
Earnings Attributable to AEP Common Shareholders	$108.0	$97.2

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2016	2015
	(in millions of KWhs)	
Retail:		
Residential	6,241	7,266
Commercial	5,787	5,915
Industrial	5,498	5,280
Miscellaneous	166	161
Total Retail (a)	17,692	18,622
Wholesale (b)	323	534
Total KWhs	18,015	19,156

(a) Represents energy delivered to distribution customers.
(b) Primarily Ohio’s contractually obligated purchases of OVEC power sold into PJM.

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 the eastern region have a larger effect on revenues than changes in the 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 March 31, 2016	2015
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,691	2,438
Normal – Heating (b)	1,919	1,881
Actual – Cooling (c)	1	—
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	121	320
Normal – Heating (b)	194	188
Actual – Cooling (d)	159	41
Normal – Cooling (b)	109	109

(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.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

First Quarter of 2015	$97.2
Changes in Gross Margin:	
Retail Margins	54.8
Off-System Sales	(10.9)
Transmission Revenues	(20.6)
Other Revenues	(17.1)
Total Change in Gross Margin	6.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(5.1)
Depreciation and Amortization	11.4
Taxes Other Than Income Taxes	(1.1)
Interest and Investment Income	0.3
Carrying Costs Income	(4.6)
Allowance for Equity Funds Used During Construction	0.6
Interest Expense	2.4
Total Change in Expenses and Other	3.9
Income Tax Expense	0.7
First Quarter of 2016	$108.0

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 $55 million primarily due to the following:
- A $54 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- An $8 million increase in Texas weather-normalized margins primarily in the residential class.
- A $6 million increase in revenues associated with the Ohio Distribution Investment Rider.
- A $5 million increase in carrying charges primarily due to the collection of carrying costs on deferred capacity charges in Ohio beginning June 2015.

These increases were partially offset by:

- A $14 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- An $11 million decrease in weather-related usage in Texas.
- Margins from Off-system Sales decreased $11 million primarily due to losses from a power contract with OVEC.
- Transmission Revenues decreased $21 million primarily due to the following:
- A $30 million decrease in Network Integrated Transmission Service revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the

CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.
This decrease was partially offset by:

- A $9 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues decreased $17 million primarily due to a decrease in Texas securitization revenue offset in Depreciation and Amortization and other expense items below.

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Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $5 million primarily due to the following:
- A $25 million increase in recoverable expenses, primarily including PJM expenses and gridSMART® expenses, currently fully recovered in rate recovery riders/trackers.

These increases were partially offset by:

- A $13 million decrease due to the amortization of 2012 Ohio deferred storm expenses in 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- Depreciation and Amortization expenses decreased $11 million primarily due to a decrease in TCC’s securitization transition asset, which is partially offset in Other Revenues.
- Carrying Costs Income decreased $5 million primarily due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended March 31, 2016	2015
	(in millions)	
Transmission Revenues	$88.6	$57.9
Other Operation and Maintenance	11.7	7.8
Depreciation and Amortization	15.5	9.1
Taxes Other Than Income Taxes	21.2	16.2
Operating Income	40.2	24.8
Interest and Investment Income	—	0.1
Allowance for Equity Funds Used During Construction	12.4	11.9
Interest Expense	(11.8)	(8.6)
Income Before Income Tax Expense and Equity Earnings	40.8	28.2
Income Tax Expense	20.4	13.7
Equity Earnings of Unconsolidated Subsidiaries	24.3	21.8
Net Income	44.7	36.3
Net Income Attributable to Noncontrolling Interests	0.8	0.5
Earnings Attributable to AEP Common Shareholders	$43.9	$35.8

Summary of Net Plant in Service and CWIP for AEP Transmission Holdco

	March 31, 2016	2015
	(in millions)	
Net Plant in Service	$2,879.3	$1,832.2
CWIP	1,287.2	1,119.9

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First Quarter of 2016 Compared to First Quarter of 2015

Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

First Quarter of 2015	$35.8
Changes in Transmission Revenues:	
Transmission Revenues	30.7
Total Change in Transmission Revenues	30.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(3.9)
Depreciation and Amortization	(6.4)
Taxes Other Than Income Taxes	(5.0)
Interest and Investment Income	(0.1)
Allowance for Equity Funds Used During Construction	0.5
Interest Expense	(3.2)
Total Change in Expenses and Other	(18.1)
Income Tax Expense	(6.7)
Equity Earnings	2.5
Net Income Attributable to Noncontrolling Interests	(0.3)
First Quarter of 2016	$43.9

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates, were as follows:

- Transmission Revenues increased $31 million primarily due to an increase in projects placed in-service by AEP's wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $4 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $6 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased property taxes due to additional transmission investment.
- Interest Expense increased $3 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended March 31, 2016	2015
	(in millions)	
Revenues	$748.0	$1,170.5
Fuel, Purchased Electricity and Other	479.5	716.0
Gross Margin	268.5	454.5
Other Operation and Maintenance	93.6	100.0
Depreciation and Amortization	48.7	50.1
Taxes Other Than Income Taxes	9.9	9.1
Operating Income	116.3	295.3
Interest and Investment Income	0.5	1.0
Allowance for Equity Funds Used During Construction	0.2	—
Interest Expense	(9.0)	(10.5)
Income Before Income Tax Expense	108.0	285.8
Income Tax Expense	37.3	98.4
Net Income	70.7	187.4
Net Income Attributable to Noncontrolling Interests	—	—
Earnings Attributable to AEP Common Shareholders	$70.7	$187.4

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended March 31, 2016	2015
	(in millions of MWhs)	
Fuel Type:		
Coal	5	10
Natural Gas	4	4
Total MWhs	9	14

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First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

First Quarter of 2015	$ 187.4
Changes in Gross Margin:	
Generation	(148.3)
Retail, Trading and Marketing	(37.2)
Other	(0.5)
Total Change in Gross Margin	(186.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	6.4
Depreciation and Amortization	1.4
Taxes Other Than Income Taxes	(0.8)
Interest and Investment Income	(0.5)
Allowance for Equity Funds Used During Construction	0.2
Interest Expense	1.5
Total Change in Expenses and Other	8.2
Income Tax Expense	61.1
First Quarter of 2016	$ 70.7

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

- Generation decreased $148 million primarily due to lower capacity revenue and a decrease in wholesale energy prices.
- Retail, Trading and Marketing decreased $37 million due to the impact of favorable wholesale trading and marketing performance in 2015.

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

- Other Operation and Maintenance expenses decreased $6 million primarily due to plant retirements in June 2015.
- Income Tax Expense decreased $61 million primarily due to a decrease in pretax book income.

CORPORATE AND OTHER

First Quarter of 2016 Compared to First Quarter of 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from income of $10 million in 2015 to income of $1 million in 2016 primarily due to decreased income from the discontinued operations of AEP River Operations which was sold in November 2015.

AEP SYSTEM INCOME TAXES

First Quarter of 2016 Compared to First Quarter of 2015

Income Tax Expense decreased $92 million primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

AEP measures financial condition by the strength of its balance sheet and the liquidity provided by its cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	March 31, 2016		December 31, 2015	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$19,782.6	50.6 %	$19,572.7	51.1 %
Short-term Debt	1,221.0	3.1	800.0	2.1
Total Debt	21,003.6	53.7	20,372.7	53.2
AEP Common Equity	18,126.5	46.3	17,891.7	46.8
Noncontrolling Interests	15.2	—	13.2	—
Total Debt and Equity Capitalization	$39,145.3	100.0%	$38,277.6	100.0%

AEP's ratio of debt-to-total capital increased from 53.2% as of December 31, 2015 to 53.7% as of March 31, 2016 primarily due to an increase in short-term debt.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of March 31, 2016, AEP had $3.5 billion in aggregate credit facility commitments to support its operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of March 31, 2016, available liquidity was approximately $3.2 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,750.0	June 2017
Revolving Credit Facility	1,750.0	July 2018
Total	3,500.0	
Cash and Cash Equivalents	190.4	
Total Liquidity Sources	3,690.4	
Less: AEP Commercial Paper Outstanding	502.0	
Letters of Credit Issued	1.8	
Net Available Liquidity	$ 3,186.6	

AEP has credit facilities totaling $3.5 billion to support its commercial paper program. The credit facilities allow management to issue letters of credit in an amount up to $1.2 billion.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain 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 three months of 2016 was $585 million. The weighted-average interest rate for AEP's commercial paper during 2016 was 0.71%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit under three uncommitted facilities totaling $225 million. As of March 31, 2016, the maximum future payments for letters of credit issued under the uncommitted facilities was $190 million with maturities ranging from June 2016 to March 2017.

Securitized Accounts Receivables

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2017.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a 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 AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of March 31, 2016, this contractually-defined percentage was 51%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of March 31, 2016, AEP complied with all of the covenants contained in these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's 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 AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its 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 and AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.56 per share in April 2016. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

Management does not believe these restrictions related to AEP's various financing arrangements and regulatory requirements will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

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

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders.

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$176.4	$162.5
Net Cash Flows from Continuing Operating Activities	799.9	1,257.7
Net Cash Flows Used for Continuing Investing Activities	(1,138.3)	(1,020.9)
Net Cash Flows from (Used for) Continuing Financing Activities	352.4	(209.3)
Net Cash Flows from Discontinued Operations	—	0.4
Net Increase in Cash and Cash Equivalents	14.0	27.9
Cash and Cash Equivalents at End of Period	$190.4	$190.4

AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

Operating Activities

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Income from Continuing Operations	$503.1	$620.2
Depreciation and Amortization	497.1	495.4
Other	(200.3)	142.1
Net Cash Flows from Continuing Operating Activities	$799.9	$1,257.7

Net Cash Flows from Continuing Operating Activities were $800 million in 2016 consisting primarily of Income from Continuing Operations of $503 million and $497 million of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Protecting Americans from Tax Hikes Act of 2015 and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Continuing Operating Activities were $1.3 billion in 2015 consisting primarily of Income from Continuing Operations of $620 million and $495 million of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2014 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.

Investing Activities

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Construction Expenditures	$(1,203.5)	$(1,077.0)
Acquisitions of Nuclear Fuel	(45.5)	(51.8)
Other	110.7	107.9
Net Cash Flows Used for Continuing Investing Activities	$(1,138.3)	$(1,020.9)

Net Cash Flows Used for Continuing Investing Activities were $1.1 billion in 2016 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Continuing Investing Activities were $1 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Three Months Ended March 31,	
	2016	2015
	(in millions)	
Issuance of Common Stock, Net	$12.1	$30.4
Issuance/Retirement of Debt, Net	623.7	44.0
Dividends Paid on Common Stock	(276.5)	(261.0)
Other	(6.9)	(22.7)
Net Cash Flows from (Used for) Continuing Financing Activities	$352.4	$(209.3)

Net Cash Flows from Continuing Financing Activities in 2016 were $352 million. AEP's net debt issuances were $624 million. The net issuances included an increase in short-term borrowing of $421 million, issuances of $400 million of senior unsecured notes and $125 million of pollution control bonds offset by retirements of $162 million of securitization bonds, $125 million of pollution control bonds and $35 million of senior unsecured and other debt notes. AEP paid common stock dividends of $277 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Continuing Financing Activities in 2015 were $209 million. AEP's net debt issuances were $44 million. The net issuances included issuances of $700 million of senior unsecured notes, $54 million of pollution control bonds and $20 million of other debt notes offset by retirements of $153 million of securitization bonds, $54 million of pollution control bonds, $32 million of senior unsecured and other debt notes and a decrease in short-term borrowing of $491 million. AEP paid common stock dividends of $261 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In April 2016, I&M retired $13 million of Notes Payable related to DCC Fuel.

In April 2016, Transource Missouri drew $6 million on an existing variable rate credit facility due in 2018.

OFF-BALANCE SHEET ARRANGEMENTS

AEP's current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that AEP enters in the normal course of business. The following identifies significant off-balance sheet arrangements:

	March 31, 2016	December 31, 2015
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$1,034.0	$ 1,034.0
Railcars Maximum Potential Loss from Lease Agreement	18.1	18.1

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 2015

Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2015 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 2015 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

New Accounting Pronouncements Adopted During the First Quarter of 2016

The FASB issued ASU 2015-01 “Income Statement – Extraordinary and Unusual Items” eliminating the concept of extraordinary items for presentation on the face of the statements of income. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements. Management adopted ASU 2015-01 effective January 1, 2016.

The FASB issued ASU 2015-05 “Customer’s Accounting for Fees paid in a Cloud Computing Arrangement” providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management adopted ASU 2015-05 prospectively, effective January 1, 2016, with no impact on results of operations, financial position or cash flows.

Pronouncements Effective in the Future

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, determine 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 FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for annual periods beginning after December 15, 2016. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

The FASB issued ASU 2015-11 “Simplifying the Measurement of Inventory” to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management does not expect the new standard to impact the Registrants’ results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

The FASB issued ASU 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for sale securities in combination with the entity’s other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

The FASB issued ASU 2016-02 "Accounting for Leases" increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard. The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact the Registrants' financial position, but not the Registrants' results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

The FASB issued ASU 2016-09 "Compensation – Stock Compensation" simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income. The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management plans to adopt ASU 2016-09 effective January 1, 2017.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including financial instruments, pension and postretirement benefits, 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

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

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk.

These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a major power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors 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 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, positions are modified 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, 2015:
MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2016

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets as of December 31, 2015	$8.6	$ 14.4	$ 143.2	$166.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(16.2)	1.3	1.4	(13.5)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	17.9	17.9
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	(0.1)	0.5	0.4
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	8.1	(27.6)	—	(19.5)
Total MTM Risk Management Contract Net Assets as of March 31, 2016	$0.5	$ (12.0)	$ 163.0	151.5
Commodity Cash Flow Hedge Contracts				(20.3)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(0.4)
Fair Value Hedge Contracts				0.5
Collateral Deposits				