AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 27, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2017
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
333-217143	AEP TRANSMISSION COMPANY, LLC (A Delaware Limited Liability Company)	46-1125168
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 the American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer
x Accelerated filer
¨ Non-accelerated filer
¨ (Do not check if a smaller reporting company)

Smaller reporting company
¨
Emerging growth company ¨

Indicate by check mark whether AEP Transmission Company, LLC, 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, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer
¨ Accelerated filer
¨ Non-accelerated filer
x (Do not check if a smaller reporting company)

Smaller reporting company
¨
Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether

the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

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

	Number of shares of common stock outstanding of the Registrants as of October 26, 2017
American Electric Power Company, Inc.	491,883,887 ($6.50 par value)
AEP Transmission Company, LLC (a)	NA
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)

(a) 100% interest is held by AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of American Electric Power Company, Inc.
NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2017

Part II. OTHER INFORMATION

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Transmission Company, LLC, 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 Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEP Transmission Holdco and an intermediate holding company that owns seven wholly-owned transmission companies.
AEPTCo Parent	AEP Transmission Company, LLC, the equity owner of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive 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.
CAIR	Clean Air Interstate Rule.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VI LLC, DCC Fuel VII, DCC Fuel VIII, DCC Fuel IX and DCC Fuel X, 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.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Cost.
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.

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Term	Meaning
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.
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.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
Market Based Mechanism	An order from the LPSC established to evaluate proposals to construct or acquire generating capacity. The LPSC directs that the market based mechanism shall be a request for proposal competitive solicitation process.
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.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
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.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.

PM	Particulate Matter.
PPA	Purchase Power 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.

Term	Meaning
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEPTCo, 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.
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.
State Transcos	AEPTCo's seven wholly-owned, FERC-regulated, transmission-only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	Formerly AEP Texas North Company, now a division of AEP Texas.
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.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project which includes the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
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 2016 Annual Report and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in AEPTCo’s 2016 Annual Report included within AEPTCo’s Registration Statement, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “could,” “would,” “project,” “continue” and simila 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:

Economic 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 and customer growth.

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

The cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and spent nuclear fuel.

Availability of necessary generation capacity, the performance of generation plants and the availability of fuel, including processed nuclear fuel, parts and service from reliable vendors.

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 any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.
Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
The ability to successfully and profitably manage competitive generation assets, including the evaluation and execution 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 2016 Annual Report and in Part II of this report. Additionally, see “Risk Factors” in the AEPTCo 2016 Annual Report included within AEPTCo’s Registration Statement.

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 third quarter of 2017 decreased by 0.7% compared to the third quarter of 2016. AEP's third quarter 2017 industrial sales increased by 1.7% compared to the third quarter of 2016. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential sales decreased 2.4% in the third quarter of 2017 compared to the third quarter of 2016. Weather-normalized commercial sales decreased by 1.3% in the third quarter of 2017 compared to the third quarter of 2016.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2017 decreased by 0.4% compared to the nine months ended September 30, 2016. AEP's industrial sales volumes for the nine months ended September 30, 2017 increased 1.6% compared to the nine months ended September 30, 2016. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential and commercial sales decreased 1.5% and 1.4%, respectively, for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016.

Merchant Generation Assets

In September 2016, AEP signed an agreement to sell Darby, Gavin, Lawrenceburg and Waterford Plants ("Disposition Plants") totaling 5,329 MWs of competitive generation to a nonaffiliated party. The sale closed in January 2017 for approximately $2.2 billion. The net proceeds from the transaction were approximately $1.2 billion in cash after taxes, repayment of debt associated with these assets and transaction fees, which resulted in an after tax gain of approximately $129 million. AEP primarily used these proceeds to reduce outstanding debt and invest in its regulated businesses including transmission, and contracted renewable projects.

The assets and liabilities included in the sale transaction have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on the balance sheet as of December 31, 2016. See "Assets and Liabilities Held for Sale" section of Note 6 for additional information.

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to Dynegy Corporation. Simultaneously, AEP signed an agreement to purchase Dynegy Corporation's 40% ownership share of Conesville Plant, Unit 4. The transactions closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition.

Management continues to evaluate potential alternatives for the remaining merchant generation assets. These potential alternatives may include, but are not limited to, transfer or sale of AEP's ownership interests, or a wind down of merchant coal-fired generation fleet operations. Management has not set a specific time frame for a decision on these assets. These alternatives could result in additional losses which could reduce future net income and cash flows and impact financial condition.

Renewable Generation Portfolio

The growth of AEP's renewable generation portfolio reflects the company's strategy to diversify generation resources to provide clean energy options to customers that meet both their energy and capacity needs.

Contracted Renewable Generation Facilities

AEP utilizes two subsidiaries within the Generation & Marketing segment to further develop its renewable portfolio. AEP OnSite Partners, LLC works directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms

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of cost reducing energy technologies. AEP OnSite Partners, LLC pursues projects where a suitable termed agreement is entered into with a creditworthy counterparty. AEP Renewables, LLC develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties. As of September 30, 2017, these subsidiaries have approximately 148 MWs of renewable generation projects in operation and $292 million of capital costs have been incurred related to these projects. In addition, as of September 30, 2017, these subsidiaries have approximately 42 MWs of renewable generation projects under construction and estimated capital costs of $54 million related to these projects. As of September 30, 2017, total estimated capital costs related to these renewable generation projects were approximately $346 million.

Regulated Renewable Generation Facilities

In July 2017, APCo submitted filings with the Virginia SCC and the WVPSC requesting regulatory approval to acquire two wind generation facilities totaling approximately 225 MW of wind generation. The wind generating facilities are located in West Virginia and Ohio and, if approved, are anticipated to be in-service in the second half of 2019. APCo will assume ownership of the facilities at or near the anticipated in-service date. APCo currently plans to sell the Renewable Energy Certificates associated with the generation from these facilities.

In July 2017, PSO and SWEPCo submitted filings with the OCC, LPSC, APSC and PUCT requesting various regulatory approvals needed to fully proceed with the Wind Catcher Project. The Wind Catcher Project includes the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles. Total investment for the project is estimated to be $4.5 billion and will serve both retail and FERC wholesale load. PSO and SWEPCo will have a 30% and 70% ownership share, respectively, in these assets. The wind generating facility is located in Oklahoma and, if approved by all state commissions, is anticipated to be in-service by the end of 2020. In July 2017, the LPSC approved SWEPCo's request for an exemption to the Market Based Mechanism. In August 2017, the Oklahoma Attorney General filed a motion to dismiss with the OCC. In August 2017, the motion to dismiss was denied by the OCC. Hearings at the APSC, LPSC, OCC and PUCT are scheduled in the first quarter of 2018.

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. As restoration efforts are ongoing, AEP Texas' total costs related to this storm are not yet known. AEP Texas' current estimated cost is approximately $250 million to $300 million, including capitalized expenditures. AEP Texas currently estimates that it will incur approximately $90 million of operation and maintenance costs related to service restoration efforts. AEP Texas has a PUCT approved catastrophe reserve in base rates and can defer incremental storm expenses. AEP Texas currently recovers approximately $1 million of storm costs annually through base rates. As of September 30, 2017, the total balance of AEP Texas' deferred storm costs is approximately $97 million including approximately $73 million of incremental storm expenses as a regulatory asset related to Hurricane Harvey. Management is currently in the early stages of analyzing the impact of potential insurance claims and recoveries and, at this time, cannot estimate this amount. Any future insurance recoveries received will be applied to and will offset the regulatory asset and property, plant and equipment, as applicable. AEP Texas is currently evaluating recovery options for the regulatory asset; however, management believes the asset is probable of recovery. The other named hurricanes did not have a material impact on AEP's operations in the third quarter of 2017. If the ultimate costs of the incident are not recovered by insurance or through the regulatory process, it could have an adverse effect on future net income, cash flows and financial condition.

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 MWs) 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%).

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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 (subject to prudence review) and through SWEPCo's wholesale customers under FERC-based rates. As of September 30, 2017, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. In October 2017, the LPSC staff filed a prudence review of the Turk Plant. See "Louisiana Turk Plant Prudence Review" section of Note 4.

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.

June 2015 - May 2018 ESP Including PPA Application and Proposed ESP Extension through 2024

In March 2016, a contested stipulation agreement related to the PPA rider application was modified and approved by the PUCO. The approved PPA rider is subject to audit and review by the PUCO. Consistent with the terms of a modified and approved stipulation agreement, and based upon a September 2016 PUCO order, in November 2016, OPCo refiled its amended ESP extension application and supporting testimony. The amended filing proposed to extend the ESP through May 2024 and included (a) an extension of the OVEC PPA rider, (b) a proposed 10.41% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's DIR and (e) the addition of various new riders, including a Renewable Resource Rider.

In August 2017, OPCo and various intervenors filed a stipulation agreement with the PUCO. The stipulation extends the term of the ESP through May 2024 and includes: (a) an extension of the OVEC PPA rider, (b) a proposed 10% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) rate caps related to OPCo's DIR ranging from $215 million to $290 million for the periods 2018 through 2021, (e) the addition of various new riders, including a Smart City Rider and a Renewable Generation Rider, (f) a decrease in annual depreciation rates based on a depreciation study using data through December 2015 and (g) amortization of approximately $24 million annually beginning January 2018 of OPCo's excess distribution accumulated depreciation reserve, which was $239 million as of December 31, 2015. Upon PUCO approval of the stipulation, effective January 2018, OPCo will cease recording $39 million in annual amortization previously approved to end in December 2018 in accordance with PUCO's December 2011 OPCo distribution base rate case order. In the stipulation, OPCo and intervenors agree that OPCo can request in future proceedings a change in meter depreciation rates due to retired meters pursuant to the smart grid Phase 2 project. DIR rate caps will be reset in OPCo's next distribution base rate case which must be filed by June 2020.

In October 2017, intervenor testimony opposing the stipulation agreement was filed recommending: (a) a return on common equity to not exceed 9.3% for riders earning a return on capital investments, (b) that OPCo should file a base distribution case concurrent with the conclusion of the current ESP in May 2018 and (c) denial of certain new riders proposed in OPCo's ESP extension. The stipulation is subject to review by the PUCO. A hearing at the PUCO is scheduled for November 2017.

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.

2016 SEET Filing

In December 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings. In May 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016 based upon actual earnings data for the comparable utilities risk group. Although management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's SEET treatment of the Global Settlement issues described above or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could reduce future net income and cash flows and impact financial condition. See "2016 SEET Filing" section of Note 4.

Rockport Plant, Unit 2 Selective Catalytic Reduction (SCR)

In October 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2 by December 2019. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. As of September 30, 2017, total costs incurred related to this project, including AFUDC, were approximately $17 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to I&M and KPCo and will be subject to future regulatory approval for recovery. In February 2017, the Indiana Office of Utility Consumer Counselor (OUCC) and other parties filed testimony with the IURC. The OUCC recommended approval of the CPCN but also stated that any decision regarding recovery of any under-depreciated plant due to retirement should be fully investigated in a base rate case, not in a tracker or other abbreviated proceeding. The other parties recommended either denial of the CPCN or approval of the CPCN with conditions including a cap on the amount of SCR costs allowed to be recovered in the rider and limitations on other costs related to legal issues involving the Rockport Plant, Unit 2 lease. A hearing at the IURC was held in March 2017. An order from the IURC is pending. In July 2017, I&M filed a motion with the U.S. District Court for the Southern District of Ohio to remove the requirement to install SCR technology at Rockport Plant, Unit 2. In August 2017, the district court delayed the deadline for installation of the SCR technology until March 2020.

2017 Indiana Base Rate Case

In July 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity with the annual increase to be implemented after June 2018. Upon implementation, this proposed annual increase would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018 for a credit adjustment rider related to the timing of estimated in-service dates of certain capital expenditures. The proposed annual increase includes $78 million related to increased annual depreciation rates and an $11 million increase related to the amortization of certain Cook Plant and Rockport Plant regulatory assets. The increase in depreciation rates includes a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant, including the Cook Plant Life Cycle Management Project. A hearing at the IURC is scheduled for January 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project. Additionally, the total proposed increase includes incremental costs related to the Cook Plant Life Cycle Management Program and increased vegetation management expenses. In October 2017, the MPSC staff and intervenors filed testimony. The MPSC staff recommended an annual net revenue increase of $49 million including proposed retirement dates of 2028 for both Rockport Plant, Units 1 (from 2044) and 2 (from 2022) and a return on common equity of 9.8%. The intervenors proposed certain adjustments to I&M's request including no change to the current 2044 retirement date of Rockport Plant, Unit 1, but did not propose an annual net revenue increase. Their recommended return on common equity ranged from 9.3% to 9.5%. A hearing at the MPSC is scheduled for November 2017. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Louisiana Turk Plant Prudence Review

Beginning January 2013, SWEPCo's formula rates, including the Louisiana jurisdictional share (approximately 33%) of the Turk Plant, have been collected subject to refund pending the outcome of a prudence review of the Turk Plant investment, which was placed into service in December 2012. In October 2017, the LPSC staff filed testimony contending that SWEPCo failed to continue to evaluate the suspension or cancellation of the Turk Plant during its construction period. The testimony also identified five individual items totaling approximately $51 million for potential disallowance relating to Louisiana's jurisdictional share of Turk Plant. As a result of SWEPCo's alleged failure to meet its continuing prudence obligations, the LPSC staff recommends one of the following potential unfavorable scenarios: (a) 50/50 sharing of construction cost overruns between SWEPCo and ratepayers, (b) an imposition of a cost cap similar to Texas or (c) approximately a 1% reduction of the rate on common equity for the Turk Plant. As SWEPCo has included the full value of the Turk Plant in rate base since its in-service date, SWEPCo may be required to refund potential over-collections from January 2013 through the date new rates are implemented. As of September 30, 2017, if the LPSC adopts one of these potential scenarios, and disallows the five individual items, pretax write-offs could range from $50 million to $80 million and refund provisions, including interest, could range from $15 million to $27 million. Future annual revenue reductions could range from $3 million to $4 million. Management will continue to vigorously defend against these claims. If the LPSC orders in favor of one of these scenarios, it could reduce future net income and cash flows and impact financial condition. A hearing at the LPSC is scheduled for December 2017.

2017 Oklahoma Base Rate Case

In June 2017, PSO filed an application for a base rate review with the OCC that requested a net increase in annual revenues of $156 million based upon a proposed 10% return on common equity. The proposed base rate increase includes (a) environmental compliance investments, including recovery of previously deferred environmental compliance related costs currently recorded as regulatory assets, (b) Advanced Metering Infrastructure investments, (c) additional capital investments and costs to serve PSO's customers, and (d) an annual $42 million depreciation rate increase due primarily to shorter service lives and lower net salvage estimates. As part of this filing, consistent with the OCC's final order in its previous base rate case, PSO requested recovery through 2040 of Northeastern Plant, Unit 3, including the environmental control investment, and the net book value of Northeastern Plant, Unit 4 that was retired in 2016. As of September 30, 2017, the net book value of Northeastern Plant, Unit 4 was $82 million.

In September 2017, various intervenors and the OCC staff filed testimony that included annual net revenue increase recommendations ranging from $28 million to $108 million. The recommended returns on common equity ranged from 8% to 9%. In addition, certain parties recommended investment disallowances that ranged from $27 million to $82 million related to Northeastern Plant, Unit 4 and $38 million associated with capitalized incentives. Also, a party recommended a potential refund of $43 million related to an SPP rider claiming that PSO did not adequately support the related SPP costs. The combined total impact could result in a write-off and refund of up to approximately $163 million. In addition, if similar plant recovery issues would apply to Northeastern Plant, Unit 3, the net book value of plant, including regulatory assets, materials and supplies inventory and CWIP of $346 million as of September 30, 2017, could be adversely impacted. A hearing at the OCC is scheduled to begin in October 2017.

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

2017 Kentucky Base Rate Case

In June 2017, KPCo filed a request with the KPSC for a $66 million annual increase in Kentucky base rates based upon a proposed 10.31% return on common equity with the increase to be implemented no later than January 2018. The proposed increase includes: (a) lost load since KPCo last changed base rates in July 2015, (b) incremental costs related to OATT charges from PJM not currently recovered from retail ratepayers, (c) increased depreciation expense including updated Big Sandy Plant, Unit 1 depreciation rates using a proposed retirement date of 2031, (d) recovery of other Big Sandy Plant, Unit 1 generation costs currently recovered through a retail rider and (e) incremental purchased power costs. Additionally, KPCo requested a $4 million annual increase in environmental surcharge revenues.

In August 2017, KPCo submitted a supplemental filing with the KPSC that decreased the proposed annual base rate revenue request to $60 million. The modification was due to a lower interest expense related to June 2017 debt refinancings. In October 2017, various intervenors filed testimony that included annual net revenue increase recommendations ranging from $13 million to $40 million. Intervenors recommended returns on common equity ranging from 8.6% to 8.85%. Intervenors also recommended significant delays in KPCo's proposed recoveries of: (a) depreciation expense related to Big Sandy Plant, Unit 1 (gas unit), proposing a 30-year depreciable life instead of KPCo's proposed 15-year life and (b) lease expense on Rockport Plant, Unit 2 billed from AEGCo, proposing that the approximate $100 million of lease expense for the period 2018 through 2022 be deferred with a WACC carrying charge for recovery over 10 years beginning 2023. Testimony on behalf of the Attorney General also discussed that the KPSC could consider disallowing all or a portion of the costs currently being recovered over 25 years through the Big Sandy Plant, Unit 2 retirement rider. As of September 30, 2017, KPCo's regulatory asset related to the retired Big Sandy Plant, Unit 2 was $289 million. A hearing at the KPSC is scheduled for December 2017.

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

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In September 2017, the Administrative Law Judges (ALJs) issued their proposal for decision including an annual net revenue increase of $50 million including recovery of Welsh Plant, Unit 2 environmental investments as of June 30, 2016. The ALJs proposed a return on common equity of 9.6% and recovery of but no return on Welsh Plant, Unit 2. The ALJs rejected SWEPCo's proposed transmission cost recovery mechanism. The estimated potential write-off associated with the ALJs proposal is approximately $22 million which includes $9 million associated with the lack of a return on Welsh Plant, Unit 2.

If any of these costs are not recoverable, including environmental investments and retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition. See "2016 Texas Base Rate Case" section of Note 4.

FERC Transmission Complaint - AEP's PJM Participants

In October 2016, several parties filed a joint complaint at the FERC that states the base return on common equity used by AEP's eastern transmission subsidiaries in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's PJM Transmission Rates

In November 2016, AEP's eastern transmission subsidiaries filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective

January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. Effective January 1, 2017, the modified PJM OATT formula rates were implemented, subject to refund, based on projected 2017 calendar year financial activity and projected plant balances. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's SPP Participants

In June 2017, several parties filed a joint complaint at the FERC that states the base return on common equity used by AEP's western transmission subsidiaries in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

FERC SWEPCo Power Supply Agreements Complaint - East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC)

In September 2017, ETEC and NTEC filed a complaint at the FERC that states the base return on common equity used by SWEPCo in calculating their power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

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 total approximately $850 million, excluding AFUDC. As of September 30, 2017, SWEPCo had incurred costs of $398 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of September 30, 2017, the total net book value of Welsh Plant, Units 1 and 3 was $626 million, before cost of removal, including materials and supplies inventory and CWIP.

In 2016, as approved by the APSC, SWEPCo began recovering $79 million related to the Arkansas jurisdictional share of these environmental costs, subject to prudence review in the next Arkansas filed base rate proceeding. In December 2016, the LPSC approved deferral of certain expenses related to the Louisiana jurisdictional share of environmental controls installed at Welsh Plant. In April 2017, the LPSC approved SWEPCo's recovery of these deferred costs effective May 2017. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $11 million, excluding $6 million of unrecognized equity as of September 30, 2017, (b) is subject to review by the LPSC, and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. Effective May 2017, SWEPCo began recovering $131 million in investments related to its Louisiana jurisdictional share of environmental costs. SWEPCo has sought recovery of its project costs from retail customers in its current Texas base rate case at the PUCT and is recovering these costs from wholesale customers through SWEPCo's FERC-approved agreements.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See "Welsh Plant - Environmental Impact" section of Note 4.

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. It intends to reorganize, not cease business operations. However, it is in the early stages of the bankruptcy process and it is unclear whether the company can successfully reorganize. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication, and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. I&M is evaluating how this reorganization affects these contracts. Westinghouse has stated that it intends to continue performance on I&M’s contracts, but given the importance of upcoming dates in the fuel fabrication process for Cook Plant, and their vital part in Cook Plant’s ongoing operations, I&M continues to work with Westinghouse in the bankruptcy proceedings to avoid any interruptions to that service. In the unlikely event Westinghouse rejects I&M’s contracts, or is unable to reorganize or sell its profitable businesses in the bankruptcy, Cook Plant’s operations would be significantly impacted and potentially shut down temporarily as I&M seeks other vendors for these services.

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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 2016 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 plaintiffs further allege that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. 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 plaintiffs’ claims, including the dismissal without prejudice of plaintiffs’ claims seeking compensatory damages. 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 plaintiffs 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 plaintiffs’ 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 all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, plaintiffs filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether AEGCo and I&M are in breach of certain contract provisions that plaintiffs allege operate to protect the plaintiffs’ residual interests in the unit and whether the trial court erred in dismissing plaintiffs’ claims that AEGCo and I&M breached the covenant of good faith and fair dealing.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court’s decisions which had dismissed certain of plaintiffs’ claims for breach of contract and remanding the case to the district court to enter summary judgment in plaintiffs’ favor consistent with that ruling. In April 2017, AEGCo and I&M filed a petition for rehearing with the U.S. Court of Appeals for the Sixth Circuit, which was granted. In June 2017, the U.S.

Court of Appeals for the Sixth Circuit issued an amended opinion and judgment which reverses the district court's dismissal of certain of the owners' claims under the lease agreements, vacates the denial of the owners' motion for partial summary judgment and remands the case to the district court for further proceedings. The amended opinion and judgment also affirms the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removes the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

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In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate the obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. In October 2017, the owners filed a motion to stay their claims until January 2018, to afford time for resolution of AEP's motion to modify the consent decree.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and is 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 new CAA requirements to reduce emissions 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. 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 2016 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 September 30, 2017, the AEP System had a total generating capacity of approximately 25,600 MWs, of which approximately 13,500 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 existing and proposed requirements ranges from approximately $2.2 billion to $2.8 billion between 2017 and 2025.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or reviewing and revising certain existing requirements. 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 competitive plants.

The table below represents the plants or units of plants retired in 2016 and 2015 with a remaining net book value. As of September 30, 2017, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the units listed below was approved for recovery, except for $338 million. Management is seeking or will seek recovery of the remaining net book value associated with these plants in future rate proceedings.

Company	Plant Name and Unit	Generating Capacity (in MWs)	Amounts Pending Regulatory Approval (in millions)
APCo	Kanawha River Plant	400	$ 42.3
APCo	Clinch River Plant, Unit 3	235	32.7
APCo (a)	Clinch River Plant, Units 1 and 2	470	31.8
APCo	Sporn Plant	600	17.2
APCo	Glen Lyn Plant	335	13.4
I&M (b)	Tanners Creek Plant	995	42.6
PSO (c)	Northeastern Plant, Unit 4	470	82.4
SWEPCo (d)	Welsh Plant, Unit 2	528	75.9
Total		4,033	$ 338.3

(a) 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 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively.

(b) I&M requested recovery of the Indiana (approximately 65%) and Michigan (approximately 14%) jurisdictional shares of the remaining retirement costs of Tanners Creek Plant in the 2017 Indiana and Michigan base rate cases.

(c) For Northeastern Plant, Unit 4, in November and December 2016, the OCC issued orders that provided no determination related to the return of and return on the post-retirement remaining net book value. In June 2017, PSO filed an application for a base rate review with the OCC. As part of this filing, PSO requested recovery of approximately $82 million through 2040 related to the net book value of Northeastern Plant, Unit 4 that was retired in 2016. This regulatory asset is pending regulatory approval.

(d) SWEPCo requested recovery of the Texas jurisdictional share (approximately 33%) of the net book value of Welsh Plant, Unit 2 in the 2016 Texas Base Rate Case. This regulatory asset is pending regulatory approval.

In January 2017, Dayton Power and Light Company announced the future retirement of the 2,308 MW Stuart Plant, Units 1-4. The retirement is scheduled for June 2018. Stuart Plant, Units 1-4 are operated by Dayton Power and Light Company and are jointly owned by AGR and nonaffiliated entities. AGR owns 600 MWs of the Stuart Plant, Units 1-4. As of September 30, 2017, AGR’s net book value of the Stuart Plant, Units 1-4 was zero.

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.

Proposed Modification of the New Source Review (NSR) Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between the AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when it undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree’s terms include installation of environmental control equipment on certain generating units, a declining cap on

SO_2 and NO_x emissions from the AEP System and various mitigation projects.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate an obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. The district court granted AEP’s request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until March 2020, pending resolution of the motion. AEP also proposes to retire Conesville Plant, Units 5 and 6 by December 31, 2022 and to retire one Rockport Plant unit by December 31, 2028.

AEP is seeking to modify the consent decree as a means to resolve or substantially narrow the issues in pending litigation with the owners of Rockport Plant, Unit 2. See "Rockport Plant Litigation" in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 5 - Commitments, Guarantees and Contingencies for additional information.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to the National Ambient Air Quality Standards (NAAQS) and the development of SIPs to achieve any more stringent standards; (b) implementation of the regional haze program by the states and the Federal EPA; (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standards (MATS) Rule; (d) implementation and review of the Cross-State Air Pollution Rule (CSAPR), a FIP designed to eliminate significant contributions from sources in upwind states to nonattainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil-fueled electric generating units under Section 111 of the CAA.

In March 2017, President Trump issued a series of executive orders designed to allow the Federal EPA to review and take appropriate action to revise or rescind regulatory requirements that place undue burdens on affected entities, including specific orders directing the Federal EPA to review rules that unnecessarily burden the production and use of energy. The Federal EPA published notice and an opportunity to comment on how to identify such requirements and what steps can be taken to reduce or eliminate such burdens. Future changes that result from this effort may affect AEP's compliance plans.

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

National Ambient Air Quality Standards (NAAQS)

The Federal EPA issued new, more stringent NAAQS for SO_2 in 2010, PM in 2012 and ozone in 2015. Implementation of these standards is underway. States are still in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the 2010 SO_2 NAAQS and may develop additional requirements for AEP's facilities as a result of those evaluations. In April 2017, the Federal EPA requested a stay of proceedings in the U.S. Court of Appeals for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. The Federal EPA initially announced a one-year delay in the designation of ozone non-attainment areas, but withdrew that decision. Final designations were due October 1, 2017, but have not yet been announced. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP's facilities based on the outcome of these activities.

Regional Haze

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. In January 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

The Federal EPA proposed disapproval of regional haze SIPs in a few states, including Arkansas and Texas. 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 were consistent with the environmental controls currently under construction. In September 2016, the Federal EPA published a final FIP that retains its BART determinations, but accelerates the schedule for

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implementation of certain required controls. The final rule is being challenged in the courts. In March 2017, the Federal EPA filed a motion that was granted by the U.S. Court of Appeals for the Eighth Circuit Court to hold the case in abeyance for 90 days to allow the parties to engage in settlement negotiations. Arkansas issued a proposed SIP revision to allow sources to participate in the CSAPR ozone season program in lieu of the source-specific NO_x BART requirements in the FIP, and the Federal EPA has proposed to approve that SIP revision. Arkansas and the Federal EPA have asked the Eighth Circuit to continue to hold litigation in abeyance until October 31, 2017 to facilitate settlement discussions. Management cannot predict the outcome of these proceedings.

In January 2016, the Federal EPA disapproved portions of the Texas regional haze SIP and promulgated a final FIP that did not include any BART determinations. That rule was challenged and stayed by the U.S. Court of Appeals for the Fifth Circuit Court. The parties engaged in a settlement discussion but were unable to reach an agreement. In March 2017, the U.S. Court of Appeals for the Fifth Circuit granted partial remand of the final rule. In January 2017, the Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including Welsh Plant, Unit 1. Management submitted comments on the proposal and is engaged in discussions with the Texas Commission on Environmental Quality (TCEQ) regarding the development of an alternative to source-specific BART. In September 2017, the Federal EPA issued a final rule withdrawing Texas from the annual CSAPR budget programs. The Federal EPA then issued a separate rule finalizing the regional haze requirements for electric generating units in Texas and confirmed TCEQ’s determination that no new PM limitations are required for regional haze. The Federal EPA also finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on allowance allocations as an alternative to source-specific SO_2 requirements. The proposed source-specific approach called for a wet FGD system to be installed on Welsh Plant, Unit 1. The opportunity to use emissions trading to satisfy the regional haze requirements for NO_x and SO_2 at AEP’s affected generating units provides greater flexibility and lower cost compliance options than the original proposal.

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. Management supports compliance with CSAPR programs as satisfaction of the BART requirements.

Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the CAIR, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and PM NAAQS. 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. Interstate trading of allowances is allowed on a restricted sub-regional basis.

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. The court stayed implementation of the rule. Following extended proceedings in the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court, but while the litigation was still pending, the U.S. Court of Appeals for the District of Columbia Circuit granted the Federal EPA’s 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. 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 October 2016, a final rule was issued to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduces ozone season budgets in many states and discounts the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. The rule remains in effect. Management is complying with the more stringent ozone season budgets while these petitions are being considered.

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. Compliance was required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

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. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was scheduled for May 2017, but in April 2017 the Federal EPA requested that oral argument be postponed to facilitate its review of the rule. 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 and solar installations and 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 (CPP), 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. In June 2016, the Federal EPA issued a separate proposal for the Clean Energy Incentive Program (CEIP) that was included in the model rules.

The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final CPP, 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. In April 2017, the Federal EPA withdrew its previously issued proposals for model trading rules and a CEIP.

In March 2017, the Federal EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of: (a) an Executive Order from the President of the United States titled “Promoting Energy Independence and Economic Growth” directing the Federal EPA to review the CPP and related rules; (b) the Federal EPA’s initiation of a review of the CPP and (c) a forthcoming rulemaking related to the CPP consistent with the Executive Order, if the Federal EPA determines appropriate. In this same filing, the Federal EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review and any resulting rulemaking. The District of Columbia Circuit granted the Federal EPA’s motion in part and has requested periodic status reports. In October 2017, the Federal EPA issued a proposed rule repealing the CPP and withdrawing the legal memoranda issued in connection with the rule. The Federal EPA has re-examined its legal interpretation of the “best system of emission reduction” and found that based on the statutory text, legislative history, use of similar terms elsewhere in the CAA and its own historic implementation of Section 111 that a narrower interpretation of the term limits it to those designs, processes, control technologies and other systems that can be applied directly to or at the source. Since the primary systems relied on in the CPP are not consistent with that interpretation, the Federal EPA proposes that the rule be withdrawn. Management does not expect a change in AEP’s overall strategy as a result of the proposed repeal.

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 has been challenged in the courts.

The final rule became effective in October 2015. The Federal EPA regulates CCR as a non-hazardous solid waste by its issuance of 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 to be implemented on a schedule spanning an approximate four year implementation period.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the Federal EPA to approve such programs if they are no less stringent than the minimum federal standards. The Federal EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs. In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule and asked that litigation regarding the rule be held in abeyance. The court has ordered oral argument to proceed in November 2017 and that the motion for abeyance be addressed during oral argument.

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.

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 final rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater 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. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations filed a petition for reconsideration of the rule with the Federal EPA. In April 2017, the Federal EPA granted reconsideration of the rule and issued a stay of the rule's future compliance deadlines, which has now expired. In April 2017, the U.S. Court of Appeals for the Fifth Circuit granted a stay of the litigation for 120 days. In June 2017, the Federal EPA also issued a proposal to temporarily postpone certain compliance deadlines in the rule. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017. Management submitted comments supporting the proposed postponement. Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

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 have filed petitions for a rehearing of the jurisdictional decision. In April 2016, the U.S. Court of Appeals for the Sixth Circuit denied the petitions. In January 2017, the decision was appealed to the U.S. Supreme Court, which granted certiorari to review the jurisdictional issue. The U.S. Supreme Court denied the Federal EPA's motion to hold briefing in abeyance pending further Federal EPA actions on the rule and the appeal on the jurisdictional issue continues.

In March 2017, the Federal EPA published a notice of intent to review the rule and provide an advanced notice of a proposed rulemaking consistent with the Executive Order of the President of the United States directing the Federal EPA and U.S. Army Corps of Engineers to review and rescind or revise the rule. In June 2017, the agencies signed a notice of proposed rule to rescind the definition of "waters of the United States" that was adopted in June 2015, and to re-codify the definition of that phrase as it existed immediately prior to that action. This action would effectively retain the status quo until a new rule is adopted by the agencies.

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 and AEP Texas.
  - OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.
- With the merger of TCC and TNC into AEP Utilities, Inc. to form AEP Texas, the Transmission and Distribution segment now includes certain activities related to the former AEP Utilities, Inc. that had been included in Corporate and Other.

AEP Transmission Holdco

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

Generation & Marketing

- Competitive generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.
- Contracted renewable energy investments and management services.

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.

The following discussion of AEP’s results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale, Generation Deferrals and Amortization of Generation Deferrals as presented in the Registrants statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, they do not typically impact Operating Income or Earnings Attributable to AEP Common Shareholders. Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze AEP’s financial performance in that it excludes the effect on Total Revenues caused by volatility in these expenses. Operating income, which is presented in accordance with GAAP in AEP’s statements of income, is the most directly comparable GAAP financial measure to the presentation of Gross Margin. AEP’s definition of Gross Margin may not be directly comparable to similarly titled financial measures used by other companies.

The following table presents Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Vertically Integrated Utilities	$286.3	$342.3	$626.6	$829.3
Transmission and Distribution Utilities	144.0	155.7	374.3	387.8
AEP Transmission Holdco	75.5	69.0	275.7	207.5
Generation & Marketing	33.7	(1,369.2)	246.3	(1,248.8)
Corporate and Other	5.2	36.4	(11.0)	61.7
Earnings (Loss) Attributable to AEP Common Shareholders	$544.7	$(765.8)	$1,511.9	$237.5

AEP CONSOLIDATED

Third Quarter of 2017 Compared to Third Quarter of 2016

Earnings (Loss) Attributable to AEP Common Shareholders increased from a loss of $766 million in 2016 to income of $545 million in 2017 primarily due to:

- An increase due to the impairment of certain merchant generation assets in 2016.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.

These increases were partially offset by:

- A decrease in generation revenues associated with the sale of certain merchant generation assets.
- A decrease in weather-related usage.
- The prior year reversal of income tax expense for an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS resulting in a change in the valuation allowance.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Earnings Attributable to AEP Common Shareholders increased from income of $238 million in 2016 to income of $1.5 billion in 2017 primarily due to:

- An increase due to the impairment of certain merchant generation assets in 2016.
- An increase due to the current year gain on the sale of certain merchant generation assets.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.
- Favorable rate proceedings in AEP’s various jurisdictions.

These increases were partially offset by:

- A decrease in generation revenues associated with the sale of certain merchant generation assets.
- A decrease in weather-related usage.
- A decrease in weather-normalized sales.
- A decrease in FERC wholesale municipal and cooperative revenues.
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The prior year reversal of income tax expense for an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS resulting in a change in the valuation allowance.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Revenues	$2,482.2	$2,556.3	$6,893.1	$6,927.8
Fuel and Purchased Electricity	868.6	858.3	2,368.9	2,299.8
Gross Margin	1,613.6	1,698.0	4,524.2	4,628.0
Other Operation and Maintenance	659.1	673.0	2,024.5	1,926.9
Asset Impairments and Other Related Charges	—	10.5	—	10.5
Depreciation and Amortization	288.8	277.7	845.1	815.5
Taxes Other Than Income Taxes	105.7	99.0	306.2	295.0
Operating Income	560.0	637.8	1,348.4	1,580.1
Interest and Investment Income	1.3	0.8	5.4	2.4
Carrying Costs Income	2.1	0.8	11.3	8.1
Allowance for Equity Funds Used During Construction	7.5	10.0	20.0	35.4
Interest Expense	(134.9)	(136.7)	(406.5)	(399.9)
Income Before Income Tax Expense and Equity Earnings (Loss)	436.0	512.7	978.6	1,226.1
Income Tax Expense	139.1	172.0	334.9	398.4
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.4	2.7	(4.5)	4.9
Net Income	297.3	343.4	639.2	832.6
Net Income Attributable to Noncontrolling Interests	11.0	1.1	12.6	3.3
Earnings Attributable to AEP Common Shareholders	$286.3	$342.3	$626.6	$829.3

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions of KWhs)			
Retail:				
Residential	8,488	9,575	23,226	25,373
Commercial	6,701	7,137	18,386	19,207
Industrial	8,839	8,655	25,792	25,576
Miscellaneous	603	634	1,701	1,740
Total Retail	24,631	26,001	69,105	71,896
Wholesale (a)	6,837	6,765	19,262	17,253
Total KWhs	31,468	32,766	88,367	89,149

(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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,266	1,684
Normal – Heating (b)	4	5	1,757	1,775
Actual – Cooling (c)	698	954	1,034	1,306
Normal – Cooling (b)	731	726	1,060	1,058
Western Region				
Actual – Heating (a)	—	—	539	685
Normal – Heating (b)	1	1	926	927
Actual – Cooling (c)	1,281	1,519	2,000	2,262
Normal – Cooling (b)	1,404	1,400	2,124	2,116

(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.

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Third Quarter of 2016	$342.3
Changes in Gross Margin:	
Retail Margins	(74.1)
Off-system Sales	(0.8)
Transmission Revenues	(7.6)
Other Revenues	(1.9)
Total Change in Gross Margin	(84.4)
Changes in Expenses and Other:	
Other Operation and Maintenance	13.9
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(11.1)
Taxes Other Than Income Taxes	(6.7)
Interest and Investment Income	0.5
Carrying Costs Income	1.3
Allowance for Equity Funds Used During Construction	(2.5)
Interest Expense	1.8
Total Change in Expenses and Other	7.7
Income Tax Expense	32.9
Equity Earnings (Loss) of Unconsolidated Subsidiary	(2.3)
Net Income Attributable to Noncontrolling Interest	(9.9)
Third Quarter of 2017	$286.3

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 decreased $74 million primarily due to the following:
• An $80 million decrease in weather-related usage in the eastern and western regions.
• The effect of rate proceedings in AEP’s service territories which included:
• A $17 million decrease for PSO primarily due to higher rates implemented in 2016 associated with interim rates.
• A $6 million decrease primarily due to a decrease in rates in West Virginia and Virginia.
For the rate decreases described above, $4 million relate to riders/trackers which have corresponding decreases in expense items below.
These decreases were partially offset by:
• The effect of rate proceedings in AEP’s service territories which included:
• An $11 million increase from rate proceedings in the Indiana service territory.
• An $11 million increase primarily due to rider revenue increases in Louisiana, partially offset in expense items below.
For the rate increases described above, $8 million relate to riders/trackers which have corresponding increases in expense items below.
• An $11 million increase in weather-normalized margins.

- A $4 million increase primarily due to reduced fuel and other variable production costs not recovered through fuel clauses or other trackers.

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- Transmission Revenues decreased $8 million primarily due to the following:
  - A $6 million decrease primarily due to I&M’s annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.
  - A $5 million decrease due to a net favorable accrual for SPP sponsor-funded transmission upgrades in third quarter 2016.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses decreased $14 million primarily due to the following:
  - A $15 million decrease in employee-related expenses.
  - A $10 million decrease in PJM and SPP transmission services expense not recovered through riders/trackers.
  - A $6 million decrease in storm expenses, primarily in the APCo region.

  These decreases were partially offset by:
  - A $5 million increase due to the Wind Catcher Project for PSO and SWEPCo.
  - A $5 million increase in nuclear expenses at Cook Plant.
  - A $3 million increase in vegetation management expenses, primarily at PSO and SWEPCo.
- Asset Impairments and Other Related Charges decreased $11 million due to the impairment of I&M’s Price River Coal reserves in 2016.
- Depreciation and Amortization expenses increased $11 million primarily due to the following:
  - A $15 million increase primarily due to higher depreciable base.
  - A $6 million increase due to amortization of capitalized software costs.

  These increases were partially offset by:
  - A $9 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates at PSO.
- Taxes Other Than Income Taxes increased $7 million primarily due to higher property taxes.
- Income Tax Expense decreased $33 million primarily due to a decrease in pretax book income and income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine.
- Net Income Attributable to Noncontrolling Interest increased $10 million primarily due to income tax benefits attributable to SWEPCo’s noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016
Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2016	$829.3
Changes in Gross Margin:	
Retail Margins	(123.9)
Off-system Sales	7.4
Transmission Revenues	11.0
Other Revenues	1.7
Total Change in Gross Margin	(103.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(97.6)
Asset Impairments and Other Related Charges	10.5
Depreciation and Amortization	(29.6)
Taxes Other Than Income Taxes	(11.2)
Interest and Investment Income	3.0
Carrying Costs Income	3.2
Allowance for Equity Funds Used During Construction	(15.4)
Interest Expense	(6.6)
Total Change in Expenses and Other	(143.7)
Income Tax Expense	63.5
Equity Earnings (Loss) of Unconsolidated Subsidiary	(9.4)
Net Income Attributable to Noncontrolling Interest	(9.3)
Nine Months Ended September 30, 2017	$626.6

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 decreased $124 million primarily due to the following:
- A $164 million decrease in weather-related usage in the eastern and western regions.
- A $42 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to an annual formula rate true-up and adjustments at I&M and SWEPCo.
- The effect of rate proceedings in AEP's service territories which included:
- A $14 million decrease primarily due to prior year recognition of deferred billing in West Virginia as approved by the WVPSC.
- A $9 million net decrease for PSO primarily due to revenue decreases associated with interim base rates implemented in 2016.

For the rate decreases described above, $1 million relate to riders/trackers which have corresponding decreases in expense items below.
- A $5 million decrease in weather-normalized margins.

These decreases were partially offset by:

- The effect of rate proceedings in AEP’s service territories which included:
- A $42 million increase from rate proceedings in the Indiana service territory.
- A $33 million increase due to rider revenue increases in Louisiana, Texas and Arkansas, partially offset in expense items below.
- A $6 million increase for KGPCo due to revenue increases from rate riders/trackers.

For the rate increases described above, $37 million relate to riders/trackers which have corresponding increases in expense items below.

- A $19 million increase primarily due to reduced fuel and other variable production costs not recovered through fuel clauses or other trackers.
- Margins from Off-system Sales increased $7 million primarily due to higher market prices.
- Transmission Revenues increased $11 million primarily due the following:
- A $35 million increase primarily due to increases in formula rates driven by continued investment in transmission assets. This increase is partially offset in Other Operation and Maintenance expenses below.

These increases were partially offset by:

- A $23 million decrease primarily due to I&M's annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.
- A $5 million net decrease due to a net favorable accrual for SPP sponsor-funded transmission upgrades in third quarter 2016.

Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiary and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- Other Operation and Maintenance expenses increased $98 million primarily due to the following:
- A $103 million increase in recoverable expenses, primarily PJM expenses and energy efficiency expenses fully recovered in rate recovery riders/trackers within Gross Margin above.
- A $22 million increase in vegetation management expenses, primarily at PSO and I&M.
- A $6 million increase due to a favorable land sale in 2016 in the APCo region.

These increases were partially offset by:

- A $27 million decrease in employee-related expenses.
- Asset Impairments and Other Related Charges decreased $11 million primarily due to the impairment of I&M's Price River Coal reserves in 2016.
- Depreciation and Amortization expenses increased $30 million primarily due to the following:
- A $46 million increase primarily due to higher depreciable base.
- A $15 million increase due to amortization of capitalized software costs.

These increases were partially offset by:

- A $24 million decrease primarily related to prior year higher estimated depreciation expense associated with interim rates at PSO.
- Taxes Other Than Income Taxes increased $11 million primarily due to higher property taxes.
- Allowance for Equity Funds Used During Construction decreased $15 million primarily due to completed environmental projects.
- Interest Expense increased $7 million primarily due to the following:
- A $7 million increase due to lower AFUDC borrowed funds resulting from completed environmental projects.
- A $7 million increase primarily due to higher long-term debt balances at I&M.

These increases were partially offset by:

- A $4 million decrease primarily due to the deferral of the debt component of carrying charges on environmental control costs at PSO.
- Income Tax Expense decreased $64 million primarily due to a decrease in pretax book income and income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine, partially offset by the recording of favorable state and federal income tax adjustments in 2016.
- Equity Earnings (Loss) of Unconsolidated Subsidiary decreased $9 million primarily due to a prior period income tax adjustment for DHLC, a SWEPCo unconsolidated subsidiary.
- Net Income Attributable to Noncontrolling Interest increased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This increase is offset by a decrease in Income Tax Expense.

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TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Revenues	$1,173.3	$1,275.6	$3,313.2	$3,468.5
Purchased Electricity	215.7	253.6	626.0	662.2
Amortization of Generation Deferrals	58.7	66.1	172.9	173.0
Gross Margin	898.9	955.9	2,514.3	2,633.3
Other Operation and Maintenance	303.2	358.2	882.5	1,009.5
Depreciation and Amortization	182.3	181.4	502.4	505.0
Taxes Other Than Income Taxes	133.6	132.0	387.1	373.0
Operating Income	279.8	284.3	742.3	745.8
Interest and Investment Income	1.2	1.5	5.6	5.5
Carrying Costs Income	0.5	0.9	3.0	4.0
Allowance for Equity Funds Used During Construction	0.9	2.2	6.3	10.6
Interest Expense	(61.0)	(63.2)	(182.5)	(196.0)
Income Before Income Tax Expense	221.4	225.7	574.7	569.9
Income Tax Expense	77.4	70.0	200.4	182.1
Net Income	144.0	155.7	374.3	387.8
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$144.0	$155.7	$374.3	$387.8

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions of KWhs)			
Retail:				
Residential	7,511	8,325	19,361	20,575
Commercial	6,941	7,287	19,184	19,676
Industrial	5,575	5,518	16,992	16,522
Miscellaneous	185	187	516	528
Total Retail (a)	20,212	21,317	56,053	57,301
Wholesale (b)	585	654	1,749	1,389
Total KWhs	20,797	21,971	57,802	58,690

(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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,500	1,929
Normal – Heating (b)	6	7	2,091	2,110
Actual – Cooling (c)	642	900	957	1,209
Normal – Cooling (b)	670	664	960	956
Western Region				
Actual – Heating (a)	—	—	103	123
Normal – Heating (b)	—	—	199	198
Actual – Cooling (d)	1,393	1,534	2,640	2,619
Normal – Cooling (b)	1,364	1,358	2,396	2,384

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

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Third Quarter of 2016	$155.7
Changes in Gross Margin:	
Retail Margins	(58.7)
Off-system Sales	(11.6)
Transmission Revenues	7.6
Other Revenues	5.7
Total Change in Gross Margin	(57.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	55.0
Depreciation and Amortization	(0.9)
Taxes Other Than Income Taxes	(1.6)
Interest and Investment Income	(0.3)
Carrying Costs Income	(0.4)
Allowance for Equity Funds Used During Construction	(1.3)
Interest Expense	2.2
Total Change in Expenses and Other	52.7
Income Tax Expense	(7.4)
Third Quarter of 2017	$144.0

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

- Retail Margins decreased $59 million primarily due to the following:
  - A $52 million decrease in Ohio revenues associated with the Universal Service Fund (USF) surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operating and Maintenance expenses below.
  - An $18 million net decrease in recovery of equity carrying charges related to the Ohio Phase-In Recovery Rider (PIRR), net of associated amortizations.
  - An $8 million decrease in revenues associated with smart grid riders in Ohio. This decrease was offset in expense items below.
  - A $7 million decrease in weather-related usage in Texas.
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh in Ohio. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes below.

  These decreases were partially offset by:
  - A $14 million increase in AEP Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $12 million favorable impact in Ohio due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net margin related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- Margins from Off-system Sales decreased $12 million due to current year losses from a power contract with OVEC which is deferred in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

- Transmission Revenues increased $8 million primarily due to recovery of increased transmission investment in ERCOT.
- Other Revenues increased $6 million primarily due to an increase in Texas securitization revenue, offset in other expense items below.

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

- Other Operation and Maintenance expenses decreased $55 million primarily due to the following:
  - A $52 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $5 million decrease in employee-related expenses.
  - A $3 million decrease in recoverable smart grid expenses in Ohio. This decrease was offset in Retail Margins above.

  These decreases were partially offset by:
  - A $6 million increase in storm expenses, primarily in the Texas region.
- Depreciation and Amortization expenses increased $1 million primarily due to the following:
  - An $11 million increase primarily due to securitization amortizations related to transition funding, offset in Other Revenues above.
  - A $2 million increase due to amortization of capitalized software costs.

  These increases were partially offset by:
  - A $5 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $4 million decrease in amortization expenses for the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
  - A $4 million decrease in recoverable smart grid rider depreciation expenses in Ohio. This decrease was offset in Retail Margins above.
- Taxes Other Than Income Taxes increased $2 million primarily due to the following:
  - A $7 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

  This increase was partially offset by:
  - A $5 million decrease in state excise taxes due to a decrease in metered KWh in Ohio.
- Interest Expense decreased $2 million primarily due to a decrease in the Texas securitization transition assets as a result of the final maturity of the first Texas securitization bond. This decrease was offset by a corresponding decrease in Other Revenues above.
- Income Tax Expense increased $7 million primarily due to the recording of favorable federal income tax adjustments in 2016 and other book/tax differences which are accounted for on a flow-through basis.

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Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to
Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2016	$387.8
Changes in Gross Margin:	
Retail Margins	(123.0)
Off-system Sales	(26.8)
Transmission Revenues	24.2
Other Revenues	6.6
Total Change in Gross Margin	(119.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	127.0
Depreciation and Amortization	2.6
Taxes Other Than Income Taxes	(14.1)
Interest and Investment Income	0.1
Carrying Costs Income	(1.0)
Allowance for Equity Funds Used During Construction	(4.3)
Interest Expense	13.5
Total Change in Expenses and Other	123.8
Income Tax Expense	(18.3)
Nine Months Ended September 30, 2017	$374.3

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

- Retail Margins decreased $123 million primarily due to the following:
- A $140 million decrease in Ohio revenues associated with the USF surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operating and Maintenance expenses below.
- A $14 million decrease in weather-normalized margins, primarily in the residential class.
- A $21 million decrease due to a prior year reversal of a regulatory provision resulting from a favorable court decision in Ohio.
- A $13 million decrease in revenues associated with smart grid riders in Ohio. This decrease was offset in expense items below.
- A $9 million net decrease in recovery of equity carrying charges related to the PIRR, net of associated amortizations.
- A $7 million decrease in state excise taxes due to a decrease in metered KWh in Ohio. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes.

These decreases were partially offset by:

- A $46 million favorable impact in Ohio due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net margin related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- A $40 million increase in AEP Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.

- A $6 million increase in rider revenues associated with the DIR. This increase is partially offset in other expense items below.

- Margins from Off-system Sales decreased $27 million primarily due to the following:
- A $46 million decrease in Ohio due to current year losses from a power contract with OVEC, which is deferred in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.

This decrease was partially offset by:

- An $18 million increase in Ohio primarily due to the impact of prior year losses from a power contract with OVEC which was not included in the OVEC PPA rider.
- Transmission Revenues increased $24 million primarily due to recovery of increased transmission investment in ERCOT.
- Other Revenues increased $7 million primarily due to an increase in Texas securitization revenue, offset in other expense items below.

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

- Other Operation and Maintenance expenses decreased $127 million primarily due to the following:
- A $140 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $10 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $12 million increase in PJM expenses related to the annual formula rate true-up that will be recovered in future periods.
- A $6 million increase in storm expenses, primarily in the Texas region.
- A $5 million increase in vegetation management expenses.
- Depreciation and Amortization expenses decreased $3 million primarily due to the following:
- An $11 million decrease in amortization expenses for the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
- An $8 million decrease due to recoveries of transmission cost rider carrying costs in Ohio. This decrease was partially offset in Retail Margins above.
- A $7 million decrease in recoverable DIR depreciation expense in Ohio.
- A $5 million decrease in recoverable smart grid rider depreciation expenses in Ohio. This decrease was offset in Retail Margins above.

These decreases were partially offset by:

- A $16 million increase due to securitization amortizations related to transition funding, offset in Other Revenues above.
- A $9 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
- A $6 million increase due to amortization of capitalized software costs.
- Taxes Other Than Income Taxes increased $14 million primarily due to the following:
- A $20 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

This increase were partially offset by:

- A $7 million decrease in state excise taxes due to a decrease in metered KWh in Ohio.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to larger short-term debt balances.
- Interest Expense decreased $14 million primarily due to the following:
- A $9 million decrease due to the maturity of a senior unsecured note in June 2016 in Ohio.
- A $7 million decrease in the Texas securitization transition assets due to the final maturity of the first Texas securitization bond. This decrease was offset by a corresponding decrease in Other Revenues above.
-

Income Tax Expense increased $18 million primarily due to the recording of favorable state and federal income tax adjustments in 2016 and other book/tax differences which are accounted for on a flow-through basis.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(in millions)			
Transmission Revenues	$178.5	$132.4	$581.9	$382.7
Other Operation and Maintenance	23.1	12.2	54.5	32.7
Depreciation and Amortization	26.1	17.1	74.7	48.4
Taxes Other Than Income Taxes	28.6	22.7	85.0	65.7
Operating Income	100.7	80.4	367.7	235.9
Interest and Investment Income	0.1	—	0.5	—
Carrying Costs Expense	—	—	(0.1)	(0.2)
Allowance for Equity Funds Used During Construction	11.6	13.5	35.9	39.8
Interest Expense	(17.9)	(12.2)	(52.3)	(35.4)
Income Before Income Tax Expense and Equity Earnings	94.5	81.7	351.7	240.1
Income Tax Expense	38.6	35.2	142.1	103.2
Equity Earnings of Unconsolidated Subsidiaries	20.6	23.0	68.7	72.6
Net Income	76.5	69.5	278.3	209.5
Net Income Attributable to Noncontrolling Interests	1.0	0.5	2.6	2.0
Earnings Attributable to AEP Common Shareholders	$75.5	$69.0	$275.7	$207.5

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2017	September 30, 2016
	(in millions)	
Plant in Service	$5,001.4	$3,330.5
CWIP	1,392.8	1,565.8
Accumulated Depreciation	156.6	88.1
Total Transmission Property, Net	$6,237.6	$4,808.2

Third Quarter of 2017 Compared to Third Quarter of 2016

Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2016	$69.0
Changes in Transmission Revenues:	
Transmission Revenues	46.1
Total Change in Transmission Revenues	46.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(10.9)
Depreciation and Amortization	(9.0)
Taxes Other Than Income Taxes	(5.9)
Interest and Investment Income	0.1
Allowance for Equity Funds Used During Construction	(1.9)
Interest Expense	(5.7)
Total Change in Expenses and Other	(33.3)
Income Tax Expense	(3.4)
Equity Earnings	(2.4)
Net Income Attributable to Noncontrolling Interests	(0.5)
Third Quarter of 2017	$75.5

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 $46 million primarily due to an increase in formula rates driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $9 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $6 million primarily due to increased property taxes as a result of additional transmission investment.
- Interest Expense increased $6 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $3 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Reconciliation of Nine Months Ended September 30, 2016 to Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2016	$207.5
Changes in Transmission Revenues:	
Transmission Revenues	199.2
Total Change in Transmission Revenues	199.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(21.8)
Depreciation and Amortization	(26.3)
Taxes Other Than Income Taxes	(19.3)
Interest and Investment Income	0.5
Carrying Costs Expense	0.1
Allowance for Equity Funds Used During Construction	(3.9)
Interest Expense	(16.9)
Total Change in Expenses and Other	(87.6)
Income Tax Expense	(38.9)
Equity Earnings	(3.9)
Net Income Attributable to Noncontrolling Interests	(0.6)
Nine Months Ended September 30, 2017	$275.7

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 $199 million primarily due to the current year favorable impact of the modification of the PJM OATT formula rates combined with an increase driven by continued investment in transmission assets.

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

- Other Operation and Maintenance expenses increased $22 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $26 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $19 million primarily due to increased property taxes as a result of additional transmission investment.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to the FERC transmission complaint and an increase in the amount of short-term debt, offset by an increase in the CWIP balance.
- Interest Expense increased $17 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $39 million primarily due to an increase in pretax book income.
- Equity Earnings decreased $4 million primarily due to lower earnings at ETT resulting from increased property taxes, depreciation expense, and decreased AFUDC, partially offset by increased revenues. The revenue increase is primarily due to interim rate increases in the third quarter of 2016 and higher loads, partially offset by an ETT rate reduction that went into effect in March 2017.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions)			
Revenues	$465.5	$859.4	$1,467.5	$2,291.2
Fuel, Purchased Electricity and Other	354.6	567.4	1,062.7	1,490.6
Gross Margin	110.9	292.0	404.8	800.6
Other Operation and Maintenance	56.5	95.8	211.4	290.2
Asset Impairments and Other Related Charges	(2.5)	2,254.4	10.6	2,254.4
Gain on Sale of Merchant Generation Assets	—	—	(226.4)	—
Depreciation and Amortization	6.2	50.5	17.5	149.8
Taxes Other Than Income Taxes	3.2	8.7	8.9	29.0
Operating Income (Loss)	47.5	(2,117.4)	382.8	(1,922.8)
Interest and Investment Income	2.7	0.3	7.9	1.2
Interest Expense	(4.0)	(9.5)	(14.7)	(27.1)
Income (Loss) Before Income Tax Expense	46.2	(2,126.6)	376.0	(1,948.7)
Income Tax Expense (Credit)	12.5	(757.4)	129.7	(699.9)
Net Income (Loss)	33.7	(1,369.2)	246.3	(1,248.8)
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$33.7	$(1,369.2)	$246.3	$(1,248.8)

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(in millions of MWhs)			
Fuel Type:				
Coal	2	8	10	19
Natural Gas	—	4	2	11
Total MWhs	2	12	12	30

Third Quarter of 2017 Compared to Third Quarter of 2016
Reconciliation of Third Quarter of 2016 to Third Quarter of 2017
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2016	$(1,369.2)
Changes in Gross Margin:	
Generation	(175.4)
Retail, Trading and Marketing	(10.1)
Other	4.4
Total Change in Gross Margin	(181.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	39.3
Asset Impairments and Other Related Charges	2,256.9
Depreciation and Amortization	44.3
Taxes Other Than Income Taxes	5.5
Interest and Investment Income	2.4
Interest Expense	5.5
Total Change in Expenses and Other	2,353.9
Income Tax Expense	(769.9)
Third Quarter of 2017	$33.7

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 $175 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- Retail, Trading and Marketing decreased $10 million due to lower retail margins in 2017 partially offset by favorable wholesale trading and marketing performance in 2017.
- Other increased $4 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $39 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- Asset Impairments and Other Related Charges decreased $2.3 billion due to the asset impairment of certain merchant generation assets in 2016.
- Depreciation and Amortization expenses decreased $44 million primarily due to the sale and impairment of certain merchant generation assets.
- Taxes Other Than Income Taxes decreased $6 million primarily due to the sale of certain merchant generation assets.
- Interest Expense decreased $6 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.

- Income Tax Expense increased $770 million primarily due to an increase in pretax book income resulting primarily from the impairment of certain merchant generation assets in 2016.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016
Reconciliation of Nine Months Ended September 30, 2016
to Nine Months Ended September 30, 2017
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

Nine Months Ended September 30, 2016	$(1,248.8)
Changes in Gross Margin:	
Generation	(376.2)
Retail, Trading and Marketing	(33.6)
Other	14.0
Total Change in Gross Margin	(395.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	78.8
Asset Impairments and Other Related Charges	2,243.8
Gain on Sale of Merchant Generation Assets	226.4
Depreciation and Amortization	132.3
Taxes Other Than Income Taxes	20.1
Interest and Investment Income	6.7
Interest Expense	12.4
Total Change in Expenses and Other	2,720.5
Income Tax Expense	(829.6)
Nine Months Ended September 30, 2017	$246.3

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 $376 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- Retail, Trading and Marketing decreased $34 million primarily due to lower margins in 2017 combined with the impact of favorable wholesale trading and marketing performance in 2016.
- Other increased $14 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $79 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- Asset Impairments and Other Related Charges decreased $2.2 billion due to the asset impairment of certain merchant generation assets in 2016.
- Gain on Sale of Merchant Generation Assets increased $226 million due to the sale of certain merchant generation assets.
- Depreciation and Amortization expenses decreased $132 million primarily due to the sale and impairment of certain merchant generation assets.

- Taxes Other Than Income Taxes decreased $20 million primarily due to the sale of certain merchant generation assets.
- Interest and Investment Income increased $7 million primarily due to increased cash invested as a result of the sale of certain merchant generation assets.
- Interest Expense decreased $12 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.
- Income Tax Expense increased $830 million primarily due to an increase in pretax book income and state income taxes resulting primarily from the impairment of certain merchant generation assets in 2016.

CORPORATE AND OTHER

Third Quarter of 2017 Compared to Third Quarter of 2016

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $36 million in 2016 to $5 million in 2017 primarily due to the prior year reversal of a capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as tax return adjustments related to the prior year disposition of AEP's commercial barging operations, partially offset by the gain recognized on the sale of a cost-based investment in the third quarter of 2017.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from income of $62 million in 2016 to a loss of $11 million in 2017 primarily due to the prior year reversal of capital loss valuation allowances related to effectively settling a 2011 audit issue with the IRS and the impact of the pending sale of certain merchant generation assets as well as 2015 tax return adjustments related to the disposition of AEP's commercial barging operations, partially offset by the gain recognized on the sale of a cost-based investment in the third quarter of 2017.

AEP SYSTEM INCOME TAXES

Third Quarter of 2017 Compared to Third Quarter of 2016

Income Tax Expense increased $799 million primarily due to an increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in Income Tax Expense is also due to the third quarter of 2016 reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Income Tax Expense increased $932 million primarily due to an increase in pretax book income driven by the impairment of certain merchant generation assets in the third quarter of 2016. The increase in Income Tax Expense is also due to the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS, the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets as well as prior year tax return adjustments related to the disposition of AEP's commercial barging operations.

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

	September 30, 2017		December 31, 2016		
	(dollars in millions)				
Long-term Debt, including amounts due within one year	$20,721.7	51.9 %	$20,391.2	(a)	51.6 %
Short-term Debt	1,059.3	2.7	1,713.0		4.3
Total Debt	21,781.0	54.6	22,104.2	(a)	55.9
AEP Common Equity	18,069.1	45.3	17,397.0		44.0
Noncontrolling Interests	36.4	0.1	23.1		0.1
Total Debt and Equity Capitalization	$39,886.5	100.0 %	$39,524.3		100.0 %

(a) Amounts include debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

AEP’s ratio of debt-to-total capital decreased from 55.9% as of December 31, 2016 to 54.6% as of September 30, 2017 primarily due to a decrease in short-term debt due to the use of proceeds from the sale of Merchant Generation Assets to pay down debt. See “Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)” section of Note 6 for additional information.

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 September 30, 2017, AEP had a $3 billion revolving credit facility commitment to support its operations. In May 2017, the $500 million revolving credit facility due in June 2018 was terminated. 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 September 30, 2017, available liquidity was approximately $3 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$3,000.0	June 2021
Total	3,000.0	
Cash and Cash Equivalents	343.9	
Total Liquidity Sources	3,343.9	
Less: AEP Commercial Paper Outstanding	295.0	

Net Available Liquidity	$ 3,048.9

AEP has a $3 billion revolving credit facility to support its commercial paper program.

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 nine months of 2017 was $1.6 billion. The weighted-average interest rate for AEP’s commercial paper during 2017 was 1.19%.

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 five uncommitted facilities totaling $445 million. In August 2017, AEP executed a $75 million uncommitted letter of credit facility due in August 2018. As of September 30, 2017, the maximum future payment for letters of credit issued under the uncommitted facilities was $123 million with maturities ranging from October 2017 to September 2018.

Securitized Accounts Receivable

AEP’s receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2019.

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 September 30, 2017, this contractually-defined percentage was 52.4%. Nonperformance under these covenants could result in an event of default under 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 facility does not permit the lenders to refuse a draw on the 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 $0.62 per share in October 2017. 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.

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$210.5	$176.4
Net Cash Flows from Continuing Operating Activities	3,124.2	3,421.0
Net Cash Flows Used for Continuing Investing Activities	(1,676.6)	(3,428.7)
Net Cash Flows from (Used for) Continuing Financing Activities	(1,314.2)	46.0
Net Cash Flows Used for Discontinued Operations	—	(2.5)
Net Increase in Cash and Cash Equivalents	133.4	35.8
Cash and Cash Equivalents at End of Period	$343.9	$212.2

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

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Income from Continuing Operations	$1,527.1	$245.3
Depreciation and Amortization	1,485.9	1,550.2
Deferred Income Taxes	740.9	(47.0)
Asset Impairments and Other Related Charges	10.6	2,264.9
Gain on Sale of Merchant Generation Assets	(226.4)	—
Provision for Refund – Global Settlement, Net	(93.3)	—
Accrued Taxes, Net	(310.1)	(393.0)
Other	(10.5)	(199.4)
Net Cash Flows from Continuing Operating Activities	$3,124.2	$3,421.0

Net Cash Flows from Continuing Operating Activities were $3.1 billion in 2017 consisting primarily of Income from Continuing Operations of $1.5 billion and $1.5 billion of noncash Depreciation and Amortization. In addition, AEP recorded a gain of $226 million on the sale of certain merchant generation assets. AEP also recorded asset impairments of $11 million. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale and these impairments. Deferred and Accrued Taxes changed primarily due to the income tax impacts associated with the sale of certain merchant generation assets and the receipt of a tax refund related to the U.K. Windfall Tax. AEP refunded $93 million to customers as part of the Ohio Global Settlement reached in 2016. 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.

Net Cash Flows from Continuing Operating Activities were $3.4 billion in 2016 consisting primarily of Income from Continuing Operations of $245 million and $1.6 billion of noncash Depreciation and Amortization. AEP also had asset impairments of $2.3 billion during the third quarter of 2016. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale and Impairments for a complete discussion of asset impairments and other related charges. Accrued Taxes decreased primarily due to the impacts of bonus depreciation related to the Protecting Americans from Tax Hikes Act of 2015. Deferred Income Taxes decreased primarily due to the tax effect of the asset impairment partially offset by an increase in tax versus book temporary differences from operations, which includes provisions related to the Protecting Americans from Tax Hikes Act of 2015. 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.

Investing Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Construction Expenditures	$(3,778.2)	$(3,387.0)
Acquisitions of Nuclear Fuel	(73.2)	(127.6)
Proceeds from Sale of Merchant Generation Assets	2,159.6	—
Other	15.2	85.9
Net Cash Flows Used for Continuing Investing Activities	$(1,676.6)	$(3,428.7)

Net Cash Flows Used for Continuing Investing Activities were $1.7 billion in 2017 primarily due to Construction Expenditures for environmental, distribution and transmission investments, partially offset by the proceeds received from the sale of certain merchant generation assets. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale.

Net Cash Flows Used for Continuing Investing Activities were $3.4 billion in 2016 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Nine Months Ended September 30,	
	2017	2016
	(in millions)	
Issuance of Common Stock, Net	$—	$34.2
Issuance/Retirement of Debt, Net	(338.2)	930.3
Make Whole Premium on Extinguishment of Long-term Debt	(46.1)	—
Dividends Paid on Common Stock	(875.0)	(829.8)
Other	(54.9)	(88.7)
Net Cash Flows from (Used for) Continuing Financing Activities	$(1,314.2)	$46.0

Net Cash Flows Used for Continuing Financing Activities in 2017 were $1.3 billion. AEP's net debt retirements were $338 million. The net retirements include retirements of $978 million of senior unsecured notes, $356 million of pollution control bonds, $258 million of securitization bonds, $835 million of other debt notes and repayments of $654 million of short term debt offset by issuances of $2.3 billion of senior unsecured notes, $242 million of pollution control bonds and $254 million of other debt notes. AEP also paid $46 million for a make whole premium on the early extinguishment of debt related to the sale of certain merchant generation assets. See Note 6 - Impairment, Disposition and Assets and Liabilities Held for Sale for a complete discussion of this sale. AEP paid common stock dividends of $875 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Continuing Financing Activities in 2016 were $46 million. AEP's net debt issuances were $930 million. The net issuances included an increase in short-term borrowing of $678 million, issuances of $950 million of senior unsecured notes, $191 million of pollution control bonds and $430 million of other debt notes offset by retirements of $507 million of senior unsecured notes, $289 million of securitization bonds, $251 million of pollution control bonds and $261 million of other debt notes. AEP paid common stock dividends of $830 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In October 2017, I&M retired $1 million of Notes Payable related to DCC Fuel.

In October 2017, AEP Texas retired $41 million of 5.625% Pollution Control Bonds due in 2017.

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:

	September 30, 2017	December 31, 2016
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$812.4	$ 886.2
Railcars Maximum Potential Loss from Lease Agreement	16.9	18.4

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 2016 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2016 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 AND 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 2016 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2017

The FASB issued ASU 2015-11 "Simplifying the Measurement of Inventory" simplifying 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 adopted ASU 2015-11 prospectively, effective January 1, 2017. There was no impact on results of operations, financial position or cash flows at adoption.

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. Management adopted ASU 2016-09 effective January 1, 2017. As a result of the adoption of this guidance, management made an accounting policy election to recognize the effect of forfeitures in compensation cost when they occur. There was an immaterial impact on results of operations and financial position and no impact on cash flows at adoption.

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. Management continues to analyze the impact of the new revenue standard and related ASUs.

During 2016 and 2017, revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption.

The evaluation of revenue streams, new contracts and the new revenue standard’s disclosure requirements continues during the fourth quarter of 2017, in particular with respect to various ongoing industry implementation issues. Management will continue to analyze the related impacts to revenue recognition and monitor any new industry implementation issues that arise. Further, given industry conclusions related to implementation issues, including contributions in aid of construction and collectability, management does not anticipate changes to current accounting systems. Management plans to adopt ASU 2014-09 effective January 1, 2018.

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 sheets 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. Management continues to analyze the impact of the new lease standard. During 2016 and 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Multiple lease system options were also evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Evaluation of new lease contracts continues and the process of implementing a compliant lease system solution began in the third quarter of 2017. Management expects the new standard to impact financial position, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. Management plans to adopt ASU 2016-02 effective January 1, 2019.

The FASB issued ASU 2016-13 “Measurement of Credit Losses on Financial Instruments” requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. 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 2016-13 effective January 1, 2020.

The FASB issued ASU 2016-18 “Restricted Cash” clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows. The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

The FASB issued ASU 2017-07 “Compensation - Retirement Benefits” requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor. For 2016, AEP's actual non-service cost components were a credit of $66 million, of which approximately 37% was capitalized. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Management plans to adopt ASU 2017-07 effective January 1, 2018.

The FASB issued ASU 2017-12 “Derivatives and Hedging” amending the recognition and presentation requirements for hedge accounting activities. The objectives are to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements and reduce the complexity of applying hedge accounting. Under the new standard, the concept of recognizing hedge ineffectiveness within the statements of income for cash flow hedges, which has historically been immaterial to AEP, will be eliminated. In addition, certain required tabular disclosures relating to fair value and cash flow hedges will be modified. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2018 with early adoption permitted for any interim or annual period after August 2017. Management is analyzing the impact of this new standard, including the possibility of early adoption, and at this time, cannot estimate the impact of adoption on net income.

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. Future pronouncements issued by the FASB 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 power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward 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 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 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, 2016:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2017

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2016	$5.2	$ (118.2)	$ 164.2	$51.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(7.0)	3.4	(32.8)	(36.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	26.7	26.7
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	10.5	10.5
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	64.9			